Shutdown Plant Problems

Learning Objectives Viewgraph ==========>>>>

Learning Objectives:

1. List two major accident sequences identified at low power and shutdown plant conditions.

2. Describe the differences between full power and low power/shutdown major accident sequence classes.

3. List three systems and their components that have a history of becoming pressure locked.

4. Describe the alignment of the Residual Heat Removal System and Recirculation System when in shutdown cooling mode of RHR.

5. List the Technical Specifications violations from the events log.

Introduction

Introduction

Cover this background information prior to the event coverage.

In 1989 the Nuclear Regulatory Commission initiated a program to examine the potential risks presented during low power and shutdown conditions. Two plants, Surry (PWR) and Grand Gulf (BWR), were selected to be studied. These studies (NUREG/CR-6143/6144) and operational experiences indicated that the risk during low power and shutdown conditions may be significant.

Ask for a list of systems that are not required or can be degraded in mode 4.
SLC - pp 1-18
RR - pp 4-1
Coolant system leakage detection - pp 4-5
MSIVs - pp 4-19
HPCI - pp 5-1
ADS - pp 5-3
CS, RHR, DGs...degraded.
Primary Containemnt NOT Required

The risk associated with Grand Gulf operating in modes 4 and 5 was shown to be comparable with the risk associated with full power operation, 10^{-6} range. While the risk is low, very few systems/features of the plant are required to be available to attenuate a release should it occur. Technical specifications permits more equipment to be inoperable during low power and shutdown conditions. In certain plant conditions, primary containment is not required.

Objective #1 =========>>>>

Figure 4.10-1 presents a comparison of the mean core damage frequency percentages for the major classes of accidents from both the full-power NUREG-1150 and the low power and shutdown mode analyses NUREG/CR-6143. From this figure, obvious similarities and differences can be seen. The major similarity observed is that in both analyses the station blackout (SBO) class is important. In the full power analysis SBOs are dominate accident sequences due to the loss or degradation of multiple systems. In operating mode 3 and 4 SBOs also show up because they still cause loss or degradation of multiple systems. However, there are additional accidents that can cause loss or degradation of multiple systems because of considerations unique to those modes of operation.

Objective #2
=========>>>>
SBO Differences HIGH power - LP&S
One possible sequence would be the failure of the RHR shutdown cooling pump, followed by the pressurization of the reactor and RHR system until it fails on high pressure since the isolation valves do not have to be operable and the high pressure isolation is bypassed in mode 4.

Remaining Differences

Binding of Gate Valves

Figure 4.10-2

The major differences in the accident progression associated with the SBOs are:

- Almost all low power and shutdown mode SBOs sequences lead to an **interfacing system LOCA** where as the full power sequences do not.
- The containment is always open at the start of the low power and shutdown accidents whereas it is isolated at the start of the full power accidents.
- The probability of arresting core damage in the vessel is greater for full power accidents than for low power and shutdown conditions.

The remaining classes of accidents indicates a major differences between the two analyses. In the full power analysis, the anticipated transient without scram (ATWS) class is the second most important class while in the low power and shutdown analysis the second most important is SBO, with LOCA being number one. Given the plant conditions analyzed in the two studies, the first point that can be made is that ATWS sequences were simply not possible with the plant already in a shutdown state. On the other hand, since LOCAs were possible in both analyses, why did this class only show up in low power and shutdown results? While no detailed examination of this phenomenon was undertaken, the most likely reason for the appearance of LOCAs results is the intentional disabling of the automatic actuation of the suppression pool makeup system which is unique to the Mark III containment. Defeating automatic actuation of the suppression pool makeup is done for safety reasons. As a result, the continued use of injection systems during a LOCA require operator intervention. The difference in reliability between automatic actuation and operator action generally accounts for the fact that LOCAs survived in the low power and shutdown analysis but not in the full power analysis.

Binding of Gate Valves

Thermal binding of double-disc and flexible-wedge gate valves has been addressed by the NRC and the industry since 1977. Particularly, throughout the 1980's the industry issued a number of event reports concerning safety-related gate valve failures due to disc-binding. These failures were attributed to either pressure locking or thermal binding. Binding of gate valves in the closed position is of safety concern because gate valves have a variety of applications in safety-related systems and may be required to open during or immediately following a postulated event. During such events, valve performance is severely challenged by the rapid cooldown and depressurization rates which expose the disc to large differential pressures.

Generally valve operators are not sized to open a valve against binding forces. Pressure locking or thermal binding of gate valves represents a nonrevealing common-mode failure mechanism since normal surveillance tests may not detect or identify them.

Safety-related systems for a BWR in which valves have become pressure locked include:

Objective #3 ============>>>

- HPCI - Steam admission valve
- LPCS - Injection valve
- LPCI - Injection valve
- RCIC - Steam admission valve
- RR - Recirc pump discharge valve

A review of the events shows that there were two potential causes of pressure locking; liquid entrapment in the bonnet and high ΔP across the disc while in the closed position. Most of the events occurred during infrequent plant evolutions such as heat-up, cooldown, and testing. Pressure locking adversely affects operation of motor operated valves, and renders the associated system unavailable.

Thermal Binding Phenomenon

If a wedge gate valve is closed while the system is hot, thermal binding can occur as the system cools. The valve body and discs mechanically interfere because of their different thermal expansion and contraction characteristics. The difference in thermal contraction can cause the seats to bind the disc so tightly that reopening is extremely difficult or impossible until the valve is reheated. Several potential remedies have been suggested to alleviate this situation:

- Sightly opening and reclosing a valve periodically during a cooldown.
- Limiting valve actuator closing forces.
- Using compensating spring packs to reduce valve initial closing forces.

In general, neither ac nor dc valve motor operator sizing analyses account for the extra force needed to unseat a valve when it is thermally bound.

Pressure Locking Phenomenon

Pressure locking in flexible-wedge and double-disc gate valves generally develops because of valve design in combination with characteristics of the bonnet and specific local conditions at the valve (temperatures and pressures). The essential feature to develop pressure locking is the presence of fluid in the bonnet cavity, including the area between the discs. The fluid may enter the bonnet cavity during normal opening and closing valve cycle. Also, fluid may enter the bonnet cavity of a closed valve which has a ΔP

across the disc. The pressure differential causes the disc to move slightly away from the seat , developing a flow path for fluid so that the bonnet cavity becomes filled with high pressure fluid. Whether these situations lead to a valve pressure locking scenario depends upon the pressure of the fluid that enters the bonnet cavity, and the difference in pressure between the process fluid and bonnet cavity at the time the MOV is called upon to operate.

Consequences of Locking

These phenomena can delay the valve stroke time or cause the valve motor actuator to stall. Events at Susquehanna and FitzPatrick indicate that the RHR/LPCI and LPCS injection valves of a BWR are susceptible to pressure locking caused by bonnet cavity pressurization. In both systems the injection valve is normally shut and is require to automatically open upon receipt of an actuation signal. The testable check valve located between the reactor and injection valve is not a leak-tight valve. Leakage past the check valve can pressurize the piping between the valves and the injection valve cavity to reactor pressure. Near leak-tight seating surfaces of the injection valve may allow the valve cavity to remain pressurized and become subject to pressure locking when injection is needed during a LOCA. Under this condition, the bonnet pressure is greater than 1000 psig, while the downstream pipe suddenly depressurizes to between 400 and 500 psig. This high internal-to-external ΔP across both seating surfaces would result in double-disc drag forces, which if they exceed the available thrust of the actuator, will produce pressure locking.

When a valve disc becomes locked in the closed position due to pressure locking or thermal binding, actuation of the motor will result in locked-rotor current which will rapidly increase the temperature of the motor internals. Within 10 to 15 seconds, the heat buildup can degrade the motor's capability to deliver a specified torque, damage the motor, or both.

Mode 3/4 Event

G.E. Issued SIL 203 that ask the utilities to minimize recirc pump operation below 300 psi to extend seal life.

Hope Creek is a BWR/4 plant rated at 3293 MWt and 1067 MWe with a Mark I containment. At the time of the event the plant was operating in an action statement requiring the plant to shutdown in seven days due to an inoperable control room ventilation component. The allowed operating time of seven days was approaching expiration so the plant had commenced a reactor shutdown. As part of the normal shutdown procedure the reactor was manually scrammed by placing the mode switch in the shutdown position. The plant entered operating mode 3 at 12:18 am on July 8, 1995. Table 4.10-1 lists the sequence of events and provides a detailed description of the event to conclusion.

By using the sequence of events, attached figures, technical specifications and this text, answer learning objectives 4 and 5 in this chapter.

Summary

The reader should be aware that the statistics presented herein are for Grand Gulf. As such, this information should **not** be generalized to other nuclear power plants without first considering all relevant factors. Complete details of the Grand Gulf statistics and insights can be found in SAND94-2949.

What can be generalized, is the apparent change in dominant accident sequences from full power to low power and shutdown conditions. This is extremely important when you consider that technical specifications action statements usually require you to go to mode 3 or 4 within some time frame. The NRC felt so concerened about the apparent change in risk when entering modes 3 and 4 that they enlisted Sandia National Laboratories to evaluate the risk impact of the Limiting Conditions of Operation (LCOs) in the current Grand Gulf technical specifications. The results of the study were published in NUREG/CR-6166.

Learning Objectives

4.11 RISK MANAGEMENT

Learning Objectives:

1. Describe what is meant by the term "defense in depth," and explain how nuclear power plants have been designed to incorporate this concept.

2. Describe how probabilistic risk assessments (PRAs) of nuclear power plants can complement deterministic analyses.

3. Define the term "configuration management," and explain why configuration management is necessary in managing risk at nuclear power plants.

4. Describe methods that are used by nuclear utilities to incorporate risk insights into maintenance planning.

5. Describe how PRA results are used by the NRC for risk-based regulation.

4.11.1 Introduction

Nuclear power plants in the U.S. have been designed and constructed in accordance with deterministic analyses. The design bases of each nuclear unit are documented in its Final Safety Analysis Report (FSAR), which is updated yearly as the Updated Safety Analysis Report (USAR). Nuclear power plant operation, including maintenance and surveillance of safety-related equipment, is controlled and restricted by technical specification requirements.

Throughout the history of commercial nuclear power, the regulatory agencies (the AEC and later, the NRC) and the nuclear industry have continued to research and implement new and/or better methods of operating, maintaining, testing, and analyzing nuclear plants and equipment to reduce risk and to ensure safety. This section discusses the major regulatory and industry actions that have been or are being incorporated to address operational and accident risk management in nuclear power plants.

Define:
Deterministic Analysis
Figure 4.11-1

4.11.2 History

4.11.2.1 Deterministic Analysis

Nuclear power plants in the U. S. have been designed and constructed in accordance with deterministic analyses. Deterministic analyses involve standard good engineering practices, calculations, and judgements; and in the case of nuclear power plants, design bases which include the assumption of worst-case conditions for accident analyses. Examples of these worst-case conditions include the assumptions of an initial reactor power of greater than 100%, restrictive power distributions within the core, conservative engineering factors, the minimum-required accident mitigation equipment available, and pipe breaks of all possible sizes.

Objective #1
Defense in Depth
(Multiple levels of Assurance and Safety)

In a large nuclear generating station with a core output rated at over 3000 MW thermal, about six pounds of fission products are produced each day that the unit is operated at full power. To protect the public from these fission products during normal and accident situations, a **"defense in depth," or multiple levels of assurance and safety,** exists to minimize risk to the public from nuclear power plant operation.

Multiple Barrier Concept

A **multiple barrier concept** was used in designing and building nuclear units. The **first barrier** against fission product release is the fuel cladding. The fuel cladding consists of an enclosed cylindrical cylinder that is designed to contain fuel pellets and fission products during normal and abnormal transients. The **second barrier**, if isolated, is the reactor coolant pressure boundary. The containment systems, primary and secondary containment, provide two additional distinct fission product barriers. These barriers and the protection against the loss of each barrier are required by the Code of Federal Regulations.

Engineered safety features (ESFs) are provided in nuclear power plants to mitigate the consequences of reactor plant accidents. Sections of the General Design Criteria in Appendix A of 10 CFR, Part 50 require that specific systems be provided to serve as ESF systems. Containment systems, a residual heat removal (RHR) system, emergency core cooling systems (ECCSs), containment heat removal systems, contain ment atmosphere cleanup systems, and certain cooling water systems are typical of the systems required to be provided as ESF systems. Each of the ESF systems is designed to withstand a single failure without the loss of its protective functions during or following an accident condition. However, this single failure is limited to either an active failure during the injection phase following an accident, or an active or a passive failure during the recirculation phase. Most accident analyzes assume the loss of offsite power. This loss of offsite power is considered in addition to the "single active failure."

Redundancy

The engineered safety features which contain active components are designed with two independent trains. Examples of systems employing this design feature are the ECCSs, in which either train can satisfy all the requirements to safely shut down the plant or meet the final acceptance criteria following an accident. Redundant pumps, valves, instrument sensors, instrument strings, and logic devices are required to ensure that no single failure will prevent at least one of these trains from performing its intended function.

All engineered safety feature systems must be physically separated so that a catastrophic failure of one system will not prevent another engineered safety feature system from performing its intended function. Electrical power to the engineered safety features comes from the transmission grid via transformers, breakers and busses. **Redundant diesel generators are normally the standby power supply.**

Diversity

ESF systems are designed to remain functional if a safe shutdown earthquake occurs and are thus designated as Seismic Category I. The reactor coolant pressure boundary, reactor core and vessel internals, and systems or portions of systems that are required for emergency core cooling, post-accident containment heat removal, and post-accident containment atmosphere cleanup are designed to Seismic Category I requirements. ESF systems are also designed to include diversity. "Diversity" refers to different methods of providing the same safety protection or function. Two systems which illustrate diversity are the **core spray system** and **residual heat removal system**; both are low pressure ECCSs. Both of these systems are designed to mitigate the consequences of a loss of coolant accident (LOCA). However, the core spray system provides core cooling by spray and flooding, while the residual heat removal system utilizes flooding alone.

4.11.2.2 Probabilistic Risk Assessment

Objective #2

A PRA is an engineering tool used to quantify the risk to a facility. Risk is defined as the likelihood and consequences of rare events at nuclear power plants. These events are generally referred to as severe accidents. The PRA augments traditional deterministic engineering analyses by **providing quantitative measures of safety and thus a means of addressing the relative significance of issues in relation to plant safety**. Basically, a nuclear power plant PRA answers three questions:

- What can go wrong?
- How likely is it?
- What are the consequences?

Figure 4.11-3

Probabilistic risk assessment is a multidisciplinary approach employing various methods, including system reliability, containment response modeling, and fission release and public consequence analyses, as depicted graphically in Figure 4.11-3. A PRA treats the entire plant and its constituent systems in an integrated fashion, and thus subtle interrelationships can be discovered that are important to risk. Another important attribute of probabilistic risk assessment is that it involves analyses of both single and multiple failures. Multiple failures often lead to situations beyond the plant design basis and, in some cases, are more likely than single failures. By addressing multiple failures, a PRA can cover a broad spectrum of potential accidents at a plant.

The first comprehensive development and application of PRA techniques in the commercial nuclear power industry was the NRC-sponsored "Reactor Safety Study" (RSS). The principal objective of the RSS was to quantify the risk to the public from U.S. commercial nuclear power plants. The RSS analyzed both a BWR (Peach Bottom) and a PWR (Surry). The report of the RSS results, generally referred to as WASH-1400, was published in October of 1975. The results of the study can be summarized as follows: (1) risks from nuclear power plant operation are small as compared to non-nuclear hazards; (2) the frequencies of core melt accidents are higher than previously thought (calculated to be approximately

5 X 10^{-5} per reactor year); (3) a variety of accident types are important; (4) design-basis accidents are not dominant contributors to risk; and (5) significant differences in containment designs are important to risk. The basic PRA approach developed by the RSS is still used today.

Because the RSS was the first broad-scale application of event- and fault-tree methods to a system as complex as a nuclear power plant, it was one of the more controversial documents in the history of reactor safety. The RSS also analyzed conditions beyond the design basis and attempted to quantify risk. A group called the Lewis Committee performed a peer review of the RSS and published a report, NUREG /CR-0400, to the NRC three years later to describe the effects of the RSS results on the regulatory process. The report concluded that although the RSS had some flaws and that PRA had not been formally used in the licensing process, PRA methods were the best available and should be used to assist in the allocation of the limited resources available for the improvement of safety.

The 1979 accident at Three Mile Island (TMI) substantially changed the character of the NRC's regulatory approach. The accident revealed that perhaps nuclear reactors might not be safe enough and that new policies and approaches were required. Based on comments and recommendations from the Kemeny and Rogovin investigations of the TMI accident, a substantial program to research severe accident phenomenology was initiated (i.e., those accidents beyond the design basis which could result in core damage). It was also recommended that PRA be used more by the staff to complement its traditional, non-probabilistic methods of analyzing nuclear plant safety. Rogovin also suggested in a report to the Commissioners and the public, NUREG/CR-1250, that the NRC policy on severe accidents consider (1) more severe accidents in the licensing process and (2) probabilistic safety goals to help define what is an acceptable level of plant safety.

In late 1980, the NRC sponsored a current assessment of severe accident risks for five commercial nuclear power plants in a report called "Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants," NUREG-1150. This report included an update of the RSS risk assessments of Surry and Peach Bottom and provided the latest NRC version

Figure 4.11-6

of the state of the art in PRA models, methods, and approaches.

A summary of the insights gained from early risk assessments are as follows:

1. **As illustrated by the NUREG-1150 results and early plant PRAs, the PRAs reflect details of plant systems, operations and physical layouts. Since nuclear power plants in the U.S. are not standardized, the PRA results are very plant specific. Reactor design, equipment, location, and operation (power levels, testing and maintenance, operator actions) have large impacts on the results. Therefore, in detail, the results can differ significantly from plant to plant.**

2. Even with the differences in the detailed results between plant studies, PRAs can be used for some generic applications as listed in NUREG-1050. Some examples are:

   - Regulatory activity prioritization,
   - Safety issue evaluation,
   - Resource allocation.
   - Inspection program implementation. and
   - NRC policy development.

3. Using PRA in the decision making process has aided licensees in determining which design modifications are desirable from both risk-reduction and cost-benefit standpoints for the improvement of plant safety. PRA results have more recently been used by licensees in enforcement discussions and in support of technical specification change requests.

4. PRAs have pointed out some general differences with respect to BWRs and PWRs as classes of plants. For example, NUREG-1150 states that for BWRs, the principal initiating event contributors to core damage frequency are station blackouts (SBOs) and anticipated transients without scram (ATWSs); for PWRs, the principal contributors to core damage frequency are LOCAs. NUREG-1150 also states that the core

damage frequencies for PWRs are higher than those for BWRs, because BWRs have more redundant methods of supplying water to the reactor coolant system. However, PWRs have lower probabilities of early containment failure given a core-damage sequence, since PWR containments are larger and can withstand higher pressures than BWR containments.

4.11.2.3 Severe Accident Policy

In August of 1985, the NRC issued the "Policy Statement on Severe Accidents Regarding Future Designs and Existing Plants" that introduced the Commission's plan to address severe accident issues for existing commercial nuclear power plants. The stated policy was that the public should be subject to no undue risk from the operation of commercial nuclear reactors. A year later, in August of 1986, the NRC established both qualitative and quantitative safety goals for the nuclear industry. The qualitative safety goals are as follows:

- Individual members of the public should be provided a level of protection from the consequences of nuclear power plant operation such that individuals bear no significant additional risk to life and health.
- Societal risks to life and health from nuclear power plant operation should be comparable to or less than the risks of generating electricity by viable competing technologies and should not be significant additions to other societal risks.

The corresponding quantitative safety goals are:

- The risk to the average individual in the vicinity of a nuclear power plant of prompt fatalities that might result from a reactor accident should not exceed one-tenth of one percent of the sum of prompt fatality risks resulting from other accidents to which members of the U.S. population are generally exposed.

- The risk to the population near a nuclear power plant of cancer fatalities that might result from nuclear power plant operation should not exceed one-tenth of one percent of the sum of cancer fatality risks resulting from all other causes.

The average accident fatality rate in the U.S. is approximately 5 X 10^{-4} per individual per year, so the quantitative value for the first goal is 5 X 10^{-7} per individual per year. The "vicinity of a nuclear power plant" is defined to be the area within one mile of the plant site boundary. **The average U.S. cancer fatality rate is approximately 2 X 10^{-3} per year, so the quantitative value for the second goal is 2 X 10^{-6} per average individual per year.** The "population near a nuclear power plant" is defined as the population within 10 miles of the plant site.

However, because of arbitrary assumptions in calculations, uncertainties in PRA analyses, and gaps in equipment reliability data bases, the **safety goals are not definitive requirements, but serve as aiming points or numerical benchmarks.** In addition, it should be noted that the goals apply to the industry as a whole and not to individual plants. The safety goals are not in and of themselves meant to serve as the sole bases for licensing decisions. However, when information is available that is applicable to a specific licensing decision, it is to be considered as one factor in the licensing.

Implementation of the NRC plan to address severe accident risk included development of plant-specific examinations that would reveal vulnerabilities to severe accidents and cost-effective safety improvements that would reduce or eliminate the important vulnerabilities. In Generic Letter 88-20 dated November 23, 1988, all utilities with licensed nuclear power plants were requested to perform such examinations. The specific objectives for these individual plant examinations (IPEs) are for each utility to:

- Develop an overall appreciation of severe accident behavior,
- Understand the most likely severe accident sequences that could occur at its plant,
- Gain a more quantitative understanding of the overall probability of core damage and radioactive material releases, and

Table 4.11-1

- If necessary, reduce the overall probability of core damage and radioactive material release by appropriate modifications to procedures and hardware that would help prevent or mitigate severe accidents.

Many of the IPEs submitted to the NRC have identified unique and/or important safety features. Table 4.11-1 includes a list of insights obtained through analysis of 72 IPEs (25 BWRs and 47 PWRs) covering 106 commercial nuclear units (35 BWRs and 71 PWRs). The items in the list indicate vulnerabilities identified during the IPE process at various plants and modifications that may have been made to plant equipment or procedures to reduce the vulnerabilities and hence, the calculated core damage frequencies.

Risk- and reliability-based methods can be used for evaluating allowed outage times, scheduled or preventive maintenance, action statements requiring shutdown where shutdown risk may be substantial, surveillance test intervals, and analyses of plant configurations resulting from outages of systems or components. Because of the limitations in the IPE process such as arbitrary assumptions in calculations, uncertainties in PRA analyses, and gaps in equipment reliability data bases, the insights identified in and of themselves do not require any action by the individual licensee, but provide information on where vulnerabilities exist in its plant.

4.11.3 Risk-Based Regulation

Technical specification requirements for nuclear power plants define the limiting conditions for operation (LCOs) and surveillance requirements (SRs) to assure safety during operation. In general, these requirements are based on deterministic analyses and engineering judgements. Experiences with all modes of plant operation indicate that some elements of the requirements are unnecessarily restrictive, while a few may not be conducive to safety. Improving these requirements involves many considerations and is facilitated by the availability of plant-specific IPEs and the development of related methods for analysis. Risk-based regulation is a regulatory approach in which insights from PRAs are used in combination with deterministic system and engineering analyses to focus licensee and regulatory attention on issues commensurate with their importance to safety.

Examples of uses of risk insights for risk-based regulation include the prioritization of generic safety issues, evaluation of regulatory requirements, assessment of design or operational adequacy, evaluation of improved safety features, prioritizing inspection activities, evaluation of events, and evaluation of technical specification revision requests and enforcement issues.

Using risk- and reliability-based methods to improve technical specifications and other regulatory requirements has gained wide interest because they can:

- Quantitatively evaluate risk impacts and justify changes in requirements based on objective risk arguments, and

- Provide a defensible bases for improved requirements for regulatory applications.

Caution must be applied when using the results of risk assessments, however, because of the limitations of PRA methodology. The plant's initial PRA (and/or IPE) is a snapshot of the plant at the time the plant configuration and data were collected and analyzed. The analyses must be revised as modifications are made to the plant design, operating methods, procedures, etc., to maintain the risk assessment results current. In addition, a PRA model is not a complete or accurate model of the plant during all modes of operation. For example, for PWRs, the removal of both boric acid makeup pumps from service is not very risky during mode 1 operations; however, these pumps are very important when the achievement of the required shutdown margin in mode 5 is considered. Other limitations of PRAs include the uncertainties in the equipment failure data bases, the level of understanding of physical processes, the uncertainties in quantifying human reliability, the sensitivity of results to analytical assumptions, and modeling constraints.

Quantitative risk estimates have played an important role in addressing and resolving regulatory issues including:

- Anticipated transient without scram: Risk assessments contributed to development of the ATWS rule, 10CFR50.62, which requires all PWRs to have equipment diverse and independent from the reactor protection system for auxiliary feedwater initiation and turbine trip, requires all CE and B&W PWRs and BWRs to have a diverse scram system, provides functional requirements for the standby liquid control systems of BWRs, and requires that BWRs have equipment for automatically tripping reactor coolant recirculation pumps.

- Auxiliary feedwater (AFW) system reliability: The NRC has reviewed information provided on auxiliary feedwater systems in safety analysis reports. As part of each review, the NRC assures that an AFW system reliability analysis has been performed. The Standard Review Plan states that an acceptable AFW system should have an unreliability in the range of 10^{-4} to 10^{-5}. Compensating factors such as other methods of accomplishing the safety functions of the AFW system or other reliable methods for cooling the reactor core during abnormal conditions may be considered to justify a larger unavailability of an AFW system.

- Station blackout (loss of all ac power): Risk assessments contributed to development of the blackout rule, 10CFR50.63, which requires licensees to determine a plant-specific station blackout duration, during which core cooling and containment intergrity would be maintained, and to have procedures addressing station blackout events. The rule allows utilities several design alternatives to ensure that an operating plant can safely shut down in the event that all ac power is lost. One alternative is the installation of a full-capacity alternate ac power source that is capable of powering at least one complete set of normal safe shutdown loads.

- Backfits: There are many cases where PRAs have been used to support the backfit decision process. For example, after the TMI accident several TMI action plan issues evolved. Consumers Power performed a PRA of the Big Rock Point nuclear plant to assist in identifying those TMI generated changes which might actually have an impact on the risk at the plant. As a result, Consumers Power was able to negotiate exemptions on seven issues which did not significantly lower risk at Big Rock Point, saving over $45 million. In addition, Consumers Power used the PRA to identify changes necessary to reduce the core damage frequency at Big Rock Point to an acceptable level. The cost of a change is generally considered to be the dollar cost associated with design, licensing, implementation, operation and maintenance. Sometimes the cost of replacement power is included for a backfit requiring a plant shutdown to implement. The benefit of the change is the reduction in risk if the change is implemented. The most cost-effective change provides the most improvement in safety for the least cost. This type of cost-benefit analysis was done extensively during the ATWS rule-making process.

- Risk-based inspections: A PRA provides information on dominant accident sequences and their minimal cut sets. This information has already been used to design the risk-based portions of some plant-specific inspection programs. Inspection programs can be prioritized to address the minimization of hardware challenges, the assurance of hardware availability, and the effectiveness of plant staff actions as they relate to the systems and faults included in the dominant accident sequences. A PRA supports the assessment of a plant change by providing a quantitative measure of the relative level of safety associated with the change. This is accomplished by performing sensitivity studies. A sensitivity study is a study of how different assumptions, configurations, data, or other potential changes in the basis of the PRA impact the results.

The NRC staff is expected to use PRA results to assist in prioritizing regulatory activities, and plant inspectors are expected to use IPE results to prioritize inspection activities. **The inspectors should be alert for situations which constitute near misses.** That is, the inspector needs to recognize those events that come close to accident sequences. Recognizing the significance of events at the plant is especially important for those related to sequences initiated by an ATWS or an intersystem LOCA, which can have severe consequences. Finally, the NRC staff will be involved in more and more discussions in which PRA results are used or misused to justify a particular action or inaction. Therefore, it is important that the staff be familiar with the types of information that a PRA provides and that the staff can use PRA information accurately in discussions and decisions.

4.11.4 PRA Policy Statement and Implementation Plan

Deterministic approaches to regulation consider a set of challenges to safety and determine how those challenges should be mitigated. A probabilistic approach to regulation enhances and extends the traditional deterministic approach by:

- Allowing consideration of a broader set of potential challenges to safety,
- Providing a logical means for prioritizing these challenges based on risk significance, and
- Allowing consideration of a broader set of resources to defend against these challenges.

In August of 1995, the NRC issued the "Policy Statement on the Use of Probabilistic Risk Assessment Methods in Nuclear Regulatory Activities." The overall objectives of the policy statement are to improve the regulatory process through improved risk-informed safety decision making, through more efficient use of staff resources, through a reduction in unnecessary burdens on licensees, and through the strengthening of regulatory requirements. The policy statement contains the following elements regarding the expanded NRC use of PRA:

- Increased use of PRA in reactor regulatory matters should be implemented to the extent supported by the state of the art in PRA methods and data and in a manner that complements the NRC's deterministic approach and supports the NRC's traditional defense-in-depth philosophy.

- PRA should be used to reduce unnecessary conservatism associated with current regulatory requirements. Where appropriate, PRA should be used to support additional regulatory requirements.

- PRA evaluations in support of regulatory decisions should be as realistic as possible, and appropriate supporting data should be publicly available.

- Uncertainties in PRA evaluations need to be considered in applying the Commission's safety goals for nuclear power plants.

An agency-wide plan has been developed to implement the PRA policy statement. The scope of the PRA implementation plan includes reactor regulation, reactor safety research, analysis and evaluation of operational experience, staff training, nuclear material, and low and high level waste regulations. The plan provides mechanisms for monitoring programs and management oversight of PRA-related activities. The plan includes both ongoing and new PRA-related activities. The following are PRA-related regulatory activities that are underway within the NRC:

- Graded quality assurance,
- The maintenance rule,
- In-service inspection and testing.
- The IPE insights program,
- PRA training for the staff, and
- The reliability data rule.

Define Risk Management

4.11.4.1 Risk Management

Risk management is a means of prioritizing resources and concerns to control the level of safety. As discussed above, the NRC's and nuclear industry's use of risk analyses have shown that:

- The risk from nuclear power plant operation is generally low,
- Low cost improvements can sometimes have significant safety and economic benefits, and
- Subtle design and operational differences make it difficult to generalize dominant risk contributors from plant to plant or for a class of plants.

Because each nuclear power plant is essentially unique, the most powerful use of the PRA is as a plant-specific tool. PRAs can be used in two basic ways:

1. To support plant operations, maintenance, inspection, and planning activities; and
2. To provide information regarding changes to improve plant safety and reliability.

A plant's PRA can be used during all modes of plant operation to prioritize operations and maintenance resources to maintain safety at acceptable levels. This is accomplished, in part, by periodically updating the PRA results to keep current with plant configuration and component failure data. Importance measures can be used to indicate where preventive actions would be most beneficial and what is most important to maintain at acceptable safety levels. Based on the updated results, adjustments in plant activities and design can be made, as appropriate, to maintain the desired level of safety as indicated by the results of the PRA.

The PRA supports plant activities by providing information on the risk-significant areas in plant operation, maintenance, and design. Operations, maintenance, inspection, and planning personnel can then appropriately address these areas to control the risk at acceptable levels.

The risk-significant areas are identified by the results of the PRA. These areas are where the most attention and effort should be focused. Several useful PRA results are (1) dominant contributors (these indicate which failures are the largest contributors to the likelihood of accident sequences), (2) dominant accident sequences (these depict the failure paths that contribute most to core damage frequency), and (3) importance measures (these evaluate what contributes most to core damage, what would reduce the core damage frequency the most, and what has the greatest potential for increasing core damage frequency should it not be as reliable as desired). The major contributors to core damage by accident type for the NUREG-1150 PWR and BWR plants are shown in Figure 4.11-5, and the relative importance of BWR and PWR systems from NUREG-1050 are shown in Figures 4.11-6 and 4.11-7.

Relative importance of BWR
Figures 4.11-6

PRA results can be used in many ways during planning and operational activities at a nuclear plant. The results have an important role in risk management, maintenance planning, and risk-based inspections.

4.11.4.2 Configuration Management

Objective #3

Configuration management is one element of risk management and risk-based regulation. Configuration risk refers to the risk associated with a specific configuration of the plant. A configuration usually refers to the status of a plant in which multiple components are simultaneously unavailable. The risk associated with simultaneous outages of multiple components can be much larger than that associated with single-component outages. Technical specifications forbid outages of redundant trains within a safety system, but many other combinations of component outages can pose significant risk. In controlling operational risk, these configurations need to be analyzed. The configuration management process can be predictive in planning maintenance activities and outage schedules, and can be retrospective in evaluating the risk significance of plant events.

When a component is taken out of service for maintenance or surveillance, it has an associated downtime and risk. If the component is controlled by an allowed outage time in the Technical specifications, then this downtime is limited by the allowed outage time. Configuration management involves taking measures to avoid risk-significant configurations. It involves managing multiple equipment taken out of service at the same time, the outage times of components and systems, the availability of backup components and systems, and outage frequencies.

4.11.4.3 On-Line Maintenance

Licensees are increasing the amount and frequency of maintenance performed during power operation. Licensees' expansion of the on-line maintenance concept without thorough consideration of the safety (risk) aspects raises significant concerns. The on-line maintenance concept extends the use of technical specification allowed outage times beyond the random single failure in a system and a judgement of a reasonable time to effect repairs upon which the allowed outage times were based. Compliance with GDC single failure criteria is demonstrated during plant licensing by assuming a worst-case single failure, which often results in multiple equipment failures. This does not imply that it is acceptable to voluntarily remove equipment from service to perform on-line mainte-

Figure 4.11-12

nance on the assumption that such actions are bounded by a worst-case single failure.

A simplified qualitative model (shown graphically in Figure 4.11-12) for evaluating risk can be thought of as including three factors combined in the following way:

$$Risk = P_i \times P_m \times P_c$$

Where:

P_i = The probability of an initiating event, such as a LOCA, turbine trip, or loss of offsite power.

P_m = The probability of not being able to mitigate the event, with core damage prevention as the measure of successful mitigation.

P_c = The probability of not being able to mitigate the consequences, with containment integrity preservation as the measure of success.

The intersection of all three occurrences (initiating event occurs + mitigating equipment fails + containment fails) indicates a worst-case scenario, with core melt and subsequent radioactive release to the public (a Chernobyl-type event, for example). The intersection of the initiating event and mitigating equipment failure would be a TMI-type event, in which there is core melt without a release. If the consequence of an event is defined as financial loss (a viable definition), one would have to say that this intersection represents a serious scenario itself. Even considering the traditional definition of consequence (potential for core melt), the intersection of an initiating event and mitigating equipment failure is of concern to the utility and to the NRC.

An effective risk-assessment process includes consideration of the impact of maintenance activities on all three of these risk factors. It also considers the impact of maintenance activities on both safety-related and non-safety-related equipment. Multiple or single maintenance activities that simultaneously, or within a short time frame, impact two or more risk factors tend to increase risk the greatest. In addition, on-line maintenance tends to increase component unavailabilities. With increased scheduling of maintenance during power operation, the overall impact on train unavailability, when averaged over a year, has in many cases increased dramatically and in some cases to the point of invalidating the assumptions licensees themselves have made in their plant-specific IPEs.

Licensees may not have thoroughly considered the safety (risk) aspects of doing more on-line maintenance. Some licensees have used the concept of division or train outages to ensure that they do not have a loss of system function. In the extreme, this could result in all of the equipment in a division being out of service at a time with unexamined risk consequences, while the licensee is in literal compliance with its plant's technical specifications. For example, one facility that used a division or train approach had planned to take out of service the following equipment: the B AFW pump, the B Battery charger, the B service water pump, the B RHR pump, and the B charging pump. Because redundant train equipment was available, no LCO was exceeded. However, in the event of a design-basis transient, such as a loss of offsite power precipitated by maintenance or instrumentation calibration activities associated with non-safety-related equipment in the switchyard, the plant would be in a configuration with significant risk implications due to the diminished capability to remove decay heat at a high pressure. This is an example of maintenance simultaneously increasing the probability of an initiating event, in this case the loss of offsite power, and diminishing the plant's capability to mitigate the event.

There is a clear link between effective maintenance and safety with regard to such issues as the number of plant transients and challenges to safety systems and the associated need to maximize the operability, availability, and reliability of equipment important to safety. In many cases, the only plant changes needed to reduce the probability of core damage are procedure changes. An example at one plant included staggering the quarterly tests of the station batteries to reduce the probability of common-cause failures of the dc power supplies.

4.11.4.4 Maintenance Rule

The maintenance rule, **10CFR50.65**, becomes effective in July of 1996. One objective of the rule is to monitor the effectiveness of maintenance activities at the plants for safety-significant plant equipment in order to minimize the likelihood of failures and events caused by the lack of effective maintenance. Another objective of the rule is to ensure that safety is not degraded when maintenance activities are performed. The rule requires all nuclear power plant licensees to monitor the effectiveness of maintenance activities at their plants. The rule provides for continued emphasis on the defense-in-depth principle by including selected balance-of-plant (BOP) structures, systems, and components (SSCs); integrates risk consideration into the maintenance process; establishes an enhanced regulatory basis for inspection and enforcement of BOP maintenance-related issues; and gives a strengthened regulatory basis for ensuring that the progress achieved is sustained in the future. The maintenance rule is a results-oriented, performance-based rule. A results-oriented rule places a greater burden on the licensee to develop the supporting details needed to implement the rule, as opposed to that necessary for compliance with a traditional prescriptive, process-oriented regulation.

The maintenance rule consists of three parts: (1) goals and monitoring, (2) effective preventive maintenance, and (3) periodic evaluations and safety assessments. The scope of the rule includes safety-related structures, systems, and components that are relied upon to remain functional during and following design-basis events to ensure reactor coolant pressure boundary integrity, reactor shutdown capability, and the capability to prevent or mitigate the consequences of accidents, and those non-safety-related SSCs (1) that are relied upon to mitigate accidents or transients or are used in emergency operating procedures (EOPs), (2) whose failure could prevent safety-related SSCs from fulfilling their intended functions, or (3) whose failure could cause a scram or safety system actuation.

The rule requires that licensees monitor the performance or condition of certain structures, systems and components (SSCs) against licensee-established goals in a manner sufficient to provide reasonable assurance that those SSCs will be capable of performing their intended functions. Such monitoring would take into account industry-wide operating experience. The extent of monitoring may vary from system to system, depending on the contribution to risk. Some monitoring at the component level may be necessary; most of the monitoring could be done at the plant, system, or train level. Monitoring is not required where it has been demonstrated that an appropriate preventive maintenance program is effectively maintaining the performance of an SSC. Each licensee is required to evaluate the overall effectiveness of its maintenance activities at least every refueling cycle, again taking into account industry-wide operating experience, and to adjust its programs where necessary to ensure that the prevention of failüres is appropriately balanced with the minimization of unavailability of SSCs. Finally, in performing monitoring and maintenance activities, licensees should assess the total plant equipment that is out of service and determine the overall effect on the performance of safety functions.

In June of 1995, the NRC published a report (NUREG-1526, "Lessons Learned from Early Implementation of the Maintenance Rule at Nine Nuclear Power Plants") which documents methods, strengths, and weaknesses found with the implementation of the rule at nine plant sites. These licensees implemented the rule using the guidance in NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," which the NRC has endorsed in Regulatory Guide 1.160. Most licensees were thorough in determining which SSCs are within the scope of the rule. Some licensees incorrectly failed to classify a few non-safety-related systems as being within the scope of the rule. These systems included control room annunciators, circulating water systems, reactor coolant pump vibration monitoring systems, extraction steam systems, condenser air removal systems, screen wash water systems, generator gas systems, and turbine lubricating oil systems.

The rule requires that reliability goals be established commensurate with safety (risk). In determining which SSCs are risk significant, the typical licensee uses an expert panel consisting of a multidisciplinary team of PRA, operations, and systems experts in a working group format. The panel uses deterministic and operational experience information to complement PRA or IPE insights (importance measures) to establish the relative risk significance of SSCs. The risk determination is then used when setting goals and monitoring as required by the rule. The rule requires that appropriate corrective action shall be taken when the performance or condition of an SSC does not meet established goals. Many licensees have assigned the task of determining the root cause and developing corrective action to the responsible system engineer at the site; at some sites the expert panel participates in the process. The relative risk significance of SSCs must be reevaluated based on new information, design changes, and plant modifications.

The rule addresses preventive maintenance activities in the following manner: "adjustments shall be made where necessary to ensure that the objective of preventing failures of [SSCs] through maintenance is appropriately balanced against the objective of minimizing the effect of monitoring or preventive maintenance on the availability of [SSCs]." In other words, the unavailability of SSCs must be balanced with their reliability. Various methods are being implemented by licensees to perform these evaluations. For example, unavailability and reliability can be evaluated and balanced as an integral part of monitoring against performance criteria, taking into account performance history, preventive maintenance activities, and out-of-service times when developing the performance criteria. SSCs rendered unavailable because preventive maintenance can be trended and evaluated, and adjustments can be made where necessary to balance the unavailability with reliability. In addition, the risk contribution associated with the unavailability of the system caused by preventive maintenance activities and the risk contribution associated with the reliability of the SSC can be calculated and then used to evaluate adjustments needed to balance the contribution from each source to ensure consistency with PRA or IPE evaluations. A fourth method involves using the PRA to determine values for unavailability and reliability which, if met, would ensure that certain threshold core damage frequency values would not be exceeded, and then establish performance criteria in accordance with the resulting unavailability and reliability values.

The rule requires that when performing monitoring and preventive maintenance activities, an assessment of the total plant equipment that is out of service should be considered to determine the overall effect on performance of safety functions. As expected by the results- or performance-oriented

Objective #4

nature of the rule, various methods are being developed and implemented by licensees to fulfill this requirement. One method is a **matrix approach,** which involves listing preanalyzed configurations to supplement existing procedural guidance for voluntary on-line maintenance. The list of preanalyzed configurations is developed using importance measures to rank configurations according to risk. The equipment out-of-service matrix includes preanalyzed combinations of out-of-service equipment. A multilevel approach is then used to either (1) permit the concurrent activities, (2) require further evaluation, or (3) forbid the performance of the activities in parallel. A simplified example of an equipment out-of-service matrix is shown in Figure 4.11-16. Although the matrix approach is simple to use, it defines a limited number of combinations and may not address all operational situations and may unnecessarily limit operational flexibility.

Another method of monitoring the safety (risk) impact of plant configuration involves **using the plant IPE to evaluate the changes in the core damage frequency** resulting from equipment outages. In Figure 4.11-17, the core damage frequency was calculated for each day, based on the plant configuration that existed at the time, and plotted against time. This plant actually operated during the charted time period more conservatively than in its IPE, since the time-averaged core damage frequency, based on the actual plant configurations, was lower than the core damage frequency calculated in accordance with the IPE methodology. The "spikes" in core damage frequency correspond to periods of more risk-intensive configurations. Using this method in the predictive mode, the analysis of changes in the core damage frequency would be done during the maintenance planning and scheduling process. The maintenance schedule would be adjusted to minimize significant spikes in the core damage frequency. Figure 4.11-18 is a similar example from a different plant. This type of configuration control analysis is also being used at some foreign plants as the basis for risk-based technical specifications. In Figure 4.11-19, the magnitude of the projected increase in core damage frequency determines the amount of time the plant is allowed to be in the analyzed configuration. For example, if the calculated increase in core damage frequency is a factor of 10 or less above the baseline, the allowed duration in that configuration is 30 days; if the calculated increase is between a factor of 10 and a factor of 30 above the baseline, the allowed duration is 3 days. If the calculated increase in core damage frequency is greater than a factor of 30 above the baseline, then the configuration is not allowed.

Some licensees have implemented or are considering computer-based safety (risk) monitors that will calculate and display the risk changes associated with changes in plant configuration. Maintenance planners using the system in the predictive mode, or operators using the system on-line in real time, would be required by plant procedures to take predetermined actions and/or initiate further evaluations based on the magnitude of any indicated increase in risk (decrease in safety margin) due to a change in plant configuration or operating condition. In order for this type of system to be used for other than full power operating conditions, development and implementation of PRA models for shutdown plant conditions would be necessary.

4.11.4.5 Inspection of Configuration Management

The processes used by the licensees to schedule and plan on-line maintenance should ensure that maintenance and testing schedules are appropriately modified to account for degraded or inoperable equipment. The following are examples of questions that should help to determine the operations /maintenance level of familiarity with the process employed by a licensee in managing its scheduled maintenance activities. When planning on-line maintenance:

- Does the licensee take probabilistic risk insights into account?
- Does the licensee allow multiple train outages?
- How does the licensee take into account component and system dependencies?
- How does the licensee assure that important combinations of equipment needed for accident mitigation are not unavailable at the same time?
- By what process does the licensee determine the procedures and testing to emphasize in minimizing component unavailability and reducing the potential for accident or transient initiation, including the impact of maintenance activities involving non-safety-related equipment?
- How does the licensee determine the maximum amount of

time to allow for the maintenance and how does it determine the risk associated with the decision?

- At any given time, how much planned maintenance is in progress and how is it coordinated to minimize risk?
- Are there occurrences of scheduled maintenance activities that simultaneously, or within a short period of time, impact two or more of the risk factors discussed in section 4.11.4.3.

Specific guidance and inspection requirements for maintenance activities can be found in the NRC Inspection Manual, chapter 62700. Attachment I contains an example of an inspection report that includes various items related to the inspection of risk and configuration management:

- IPE results were used to focus the inspectors' attention on the emergency switchgear ventilation, the loss of which was identified by the IPE as the initiator of the top-ranked sequence contributing to core damage frequency (cover letter, Notice of Violation, and section 3.1.2 of the inspection report).

- The associated violation regarding the white control power light for the emergency switchgear ventilation fans was cited against 10CFR50, Appendix B, Criterion XVI, "Corrective Actions." After July, 1996, this type of violation could be cited against the maintenance rule, 10CFR50.65.

- Section 4.4 of the report discusses the fact that the technical specifications allow certain configurations of plant equipment involving auxiliary feedwater pumps and high head safety injection pumps that could potentially place the plant in an unanalyzed condition.

This report illustrates how rigorous implementation of risk-based inspection techniques and insights with regard to the plant's configuration management and on-line maintenance practices can identify and resolve safety-significant issues, thereby reducing risk and improving safety.

4.11.5 Summary

Deterministic approaches to regulation consider a set of challenges to safety and determine how those challenges should be mitigated. A probabilistic approach to regulation enhances and extends the traditional deterministic approach by (1) allowing consideration of a broader set of potential challenges to safety, (2) providing a logical means for prioritizing these challenges based on risk significance, and (3) allowing consideration of a broader set of resources to defend against these challenges.

Licensees are increasing the amount and frequency of maintenance performed during power operation. Licensees' expansion of the on-line maintenance concept without thoroughly considering the safety (risk) aspects raises significant concerns. The maintenance rule is being implemented to ensure that safety is not degraded during the performance of maintenance activities. The rule requires all nuclear power plant licensees to monitor the effectiveness of maintenance activities.

The attached inspection report's content reinforces some of the concepts discussed in this section, such as risk-informed inspections (using IPE results to prioritize inspection activities - see section 3.1.2 of the inspection report) and maintenance rule applications (same section, which discusses maintenance trending, etc), and plant configurations which are allowed by the technical specifications but put the plant in an undesirable (unsafe/unanalyzed) condition (see section 4.4 of the inspection report).

4.12 Emergency Action Levels

Learning Objectives

4.12.1 Learning Objectives

1. State the purpose of the Emergency Action Levels.
2. List the four Emergency Classification Levels.
3. List the four documents used to establish Emergency Action Levels.

Introduction

4.12.2 Introduction

OBJECTIVE 1

The purpose of an Emergency Action Level (EAL) is to trigger the declaration of an emergency classification level (ECL), which, in turn, triggers a certain level of emergency response. These actions are directed toward providing information to offsite emergency response authorities and federal agencies (e.g. plant conditions, meteorological conditions, radiological field monitoring results). Licensees' actions to respond directly to the onsite situation are governed by emergency operating procedures. Emergency action levels are used by plant personnel in determining the appropriate ECL to declare.

50.47, "Emergency Plans"

In paragraph 50.47, "Emergency Plans," of 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," paragraph (a)(1) states that no operating license for a nuclear power reactor will be issued unless a finding is made by the NRC that there is reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. For operating power reactors, 10 CFR 50.54(s)(2)(ii) requires that "If... the NRC finds that the state of emergency preparedness does not provide reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency... the Commission will determine whether the reactor shall be shutdown until such deficiencies are remedied.

Onsite and Offsite emergency response plans must meet the standards that are listed in 10 CFR 50.47 in order for the staff to make a positive finding that there is reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. One of these standards, 10 CFR 50.47(b)(4), pertains to the development of emergency classification and actions level scheme. Section IV", Content of Emergency Plans", of Appendix E to 10 CFR Part 50 also contains requirements for the development and review of EALs.

November 1980

NUREG-0654/FEMA-REP-1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and

Preparedness in Support of Nuclear Power Plants,"

January 1992, the Nuclear Utilities Management and Resource Council (NUMARC) issued Revision 2 of NUMARC / NESP-007, "Methodology for Development for Emergency Action Levels"

February 28, 2000, the Nuclear Energy Institute (NEI) submitted NEI 99-01, Methodology for Development of Emergency Action Levels

Revision 4 of Regulatory Guide 1.101

Revision 1 to NUREG-0654/FEMA-REP-1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," was published in November 1980 to provide specific acceptance criteria for complying with the standards set forth in 10 CFR 50.47.

In January 1992, the Nuclear Utilities Management and Resource Council (NUMARC) issued Revision 2 of NUMARC / NESP-007, "Methodology for Development for Emergency Action Levels", which **contained guidance on EAL development that accounted for lessons learned from the ten years of using the NUREG-0654 guidance.** The NRC stated in Revision 3 of Regulatory Guide 1.101, that revision 2 of NUMARC/NESP-007 was considered to be an acceptable alternative to the guidance provided in NUREG-0654 for development of EALs to comply with 10 CFR 50.47 and Appendix E to 10 CFR Part 50. In addition, the need for further guidance for developing emergency action levels applicable in the shutdown and refueling modes of operation were identified in Revision 3 to Regulatory Guide 1.101.

On February 28, 2000, the Nuclear Energy Institute (NEI) submitted NEI 99-01, Methodology for Development of Emergency Action Levels. The NEI 99-01 methodology is very similar to the NUMARC/NESP-007 methodology with guidance provided on initial condition (IC), example EALs and a basis for each IC and EAL. NEI 99-01 incorporated new EAL guidance for (1) Shutdown and refueling modes of plant operation, (2) permanently defueled plants, and (3) Independent Spent Fuel Storage Installations (ISFSIs).

Prior revisions to Revision 4 of Regulatory Guide 1.101 stated that "Licensees may use either NUREG-0654/FEMA-REP-1 or NUMARC/NESP-007 in developing their EAL scheme but may not use portions of both methodologies." The staff stated in Emergency Preparedness Position on Acceptable Deviations from Appendix 1 of NUREG-0654 based upon the Staff's regulatory analysis of NUMARC/NESP-007 that it recognizes that licensees who continue to use EALs based upon NUREG-0654 could benefit from the technical basis from EALs provided in NUMARC/NESP-007. However, the staff also recognized that the classification scheme must remain internally

NUREG-0654

consistent. Likewise, Licensees can benefit from guidance provided in NEI 99-01 without revising their entire EAL scheme. This is particularly true in regard to adopting guidance on EALs for cold shutdown and refueling modes of operation or for Independent Fuel Storage facilities. However, the licensee still needs to ensure that its EAL scheme remains internally consistent.

4.12.3 NUREG-0654

NUREG-0654/FEMA-REP-1 was **published to provide a common reference and guidance source** for:

- Nuclear facility operators as well as State and local governments in the development of radiological emergency response plans and preparedness in support of nuclear power plants.
- Federal Emergency management Agency (FEMA), Nuclear Regulatory Commission (NRC), and other Federal agency personnel engaged in the review of State and, Local government and licensee plans and preparedness.
- FEMA, NRC and other Federal agencies in the development of the National Radiological Emergency Plan.

NUREG-0654/FEMA-REP-1, Appendix- 1

NUREG-0654/FEMA-REP-1 was prepared as part of their responsibilities under the Atomic Energy Act, as amended, and the President's Statement of December 7, 1979, with the accompanying Fact Sheet. The responsibilities include development and promulgation of guidance to nuclear facility operators, State and local governments, in cooperation with other Federal agencies. The guidance included preparation of radiological emergency response plans and assessing the adequacy of such plans.

OBJECTIVE 2

4.12.3.1 NUREG-0654/FEMA-REP-1, Appendix- 1

Appendix 1 of NUREG-0654/FEMA-REP-1, **contains the Emergency Action Level Guidelines for Nuclear Power Plants.** Within Appendix 1 four classes of Emergency Classification Levels (EAL) are established:

- **Notification of Unusual Event**
- **Alert**
- **Site Area Emergency**
- **General Emergency**

A graduation is provided to assure fuller response preparations for more serious indicators. The rationale for the **notification and alert classes is to provide early and prompt notification of minor events** which lead to more serious consequences given operator error or equipment failure or which might be indicative of more serious conditions which are not yet realized. The **site area emergency class reflects conditions where some significant releases are likely or are occurring but where a core melt situation is not indicated based on current information.** In this situation full mobilization of emergency personnel in the near site environs is indicated as well as dispatch of monitoring teams and associated communications. The **general emergency class involves actual or imminent substantial core degradation or core melting with potential for loss of containment.** The immediate action for this class is sheltering (staying inside) rather than evacuation until assessment can be made that (1) an evacuation is indicated and (2) an evacuation, if indicated, can be completed prior to significant release and transport of radioactive material to the affected areas.

Facility licensees have primary responsibility for accident assessment. This includes prompt action to evaluate any potential risk to the public health and safety, both onsite and offsite, and timely recommendations to State and local governments concerning protective measures. The criteria for identification and classification of accidents and the notification of offsite agencies by the facility licensee are set forth in Appendix 1 of NUREG-0654/FEMA-REP-1 (Tables 4.12-1...4).

Because of the potential need to take immediate action offsite in the event of a significant radiological accident, **notifications to appropriate offsite response organizations must come directly from the facility licensee.** The response organizations which receive these notifications should have the authority and capability to take immediate predetermined actions based on recommendations from the facility licensee. These actions could include prompt notification of the public in the offsite area, followed by advisories to the public in certain areas to stay inside or, if appropriate, evacuate to predetermined relocation host areas.

Notification of Unusual Events
Table 4.12-1

Alert
Table 4.12-2

Site Area Emergency
Table 4.12-3

General Emergency
Table 4.12-4

The lowest level of emergency action levels, Notification of Unusual Events classification, is **comprised of event in progress, or which have occurred, that indicate a potential degradation of the level of safety of the station.** These types of events may progress to more severe emergency classification if they are not mitigated. No releases of radioactive material requiring offsite response or monitoring are expected unless further degradation of safety systems occurs. Examples of Notification of Unusual Events and actions for the facility licensee as well as the State and local authorities are listed in Table 4.12-1.

The next classification, Alert, is **comprised of events in progress, or which have occurred, that involve actual or potentially substantial degradation of the safety level of the station.** At this classification level, minor releases of radioactivity may occur or may have occurred. Any releases expected to be limited to small fractions of EPA Protective Action Guideline exposure levels. Examples of Alert events and actions for the facility licensee as well as the State and local authorities are listed in Table 4.12-2.

The Site Area Emergency classification is the second highest classification. Site Area Emergency is **comprised of events in progress, or which have occurred, that involve actual or potential major failure of plant functions needed for protection of the public.** Releases are not expected to exceed EPA Protective Action Guidelines, except near the Site Boundary. Examples of Site Area Emergency events and actions for the facility licensee as well as the State and local authorities are listed in Table 4.12-3.

The highest level classification, General Emergency, is comprised of events in progress, or which have occurred, that **involve actual or imminent substantial core degradation or melting with a potential for the loss of the primary containment integrity.** Release can be reasonably expected to exceed EPA Protective Action Guideline exposure levels offsite for more than the immediate site area. Examples of General Emergencies and actions for the facility licensee as well as the State and local authorities are listed in Table 4.12-4.

NUMARC/NESP-007

Symptom based

Event based

Barrier based

4.12.4 NUMARC/NESP-007

The NUMARC/NESP-007 was **developed to replace NUREG-0654/FEMA-REP-1.** The NUMARC/NESP-007 methodology provides guidance on Initial Conditions (ICs) and example Emergency Action Levels (EALs), for each IC and a basis for IC and EALs. NUMARC/NESP-007 has **three types of ICs and EALs:**

- **Symptom based**
- **Event based**
- **Barrier based**

The **symptom based EALs refer to those indicators that are measurable over a continuous spectrum, (e.g. core temperature, coolant level, radiation meter readings).** Off-normal readings on such indicators are symptoms of problems. The seriousness of a symptom depends on such factors as the degree to which technical specifications are exceeded and the capability of licensed operators to gain control and bring the indicators back to safe levels. Event-based ICs and EALs refer to discrete occurrences with potential safety significance such as a fire or severe weather. Barrier-based ICs and EALs **utilize indications of the level of challenge to the principal barriers used to assure containment of radioactive materials within a nuclear plant.** For the most important type of radioactive material, i.e., fission products, there are three principal barriers:

- Fuel cladding
- Reactor coolant system boundary
- Containment

In the NUMARC/NESP-007 methodology, the operating modes (power operation, startup, hot standby, hot shutdown, cold shutdown, refueling, and defueled) to which individual ICs apply are specified. As a plant moves from power operation through the decay heat removal process toward cold shutdown and refueling, barriers to the release of fission products may be reduced, instrumentation to detect symptoms may not be fully effective and partially disabling of safety systems may be permitted by technical specifications. For such operations, ICs and EALs tend to be event-based rather than symptom-based.

The ICs and EALs are divided into four "recognition categories" in NUMARC/NESP-007:

- **A - Abnormal Rad Levels/Radiological Effluent**
- **F - Fission Product Barrier Degradation**
- **H - Hazards or Other Conditions Affecting Plant Safety**
- **S - System Malfunction**

For recognition categories A, H, and S, ICs and associated EALs are developed for each emergency classification level. For these recognition categories, ICs are identified by a three character acronym. For example, AU2 is the second Unusual Event IC in the Abnormal Radiation Level recognition category and SS3 is the third Site Area Emergency IC in the System Malfunction recognition category.

For recognition category F, there are three ICs:

1. Loss or potential loss of the fuel clad barrier, and
2. Loss or potential loss of the RCS barrier.
3. Loss or potential loss of the containment barrier.

The EALs for each of these ICs depend on whether the reactor is a PWR or BWR. The emergency condition level is a function of the number (and extent) of fission product barrier degradation, as indicated below:

UNUSUAL EVENT	Any loss or potential loss of containment
ALERT	Any loss or any potential loss of either fuel clad or RCS
SITE AREA EMERGENCY	Loss of both fuel clad and RCS; or Potential loss of either; or Potential loss of either, and loss of any additional barrier
GENERAL EMERGENCY	Loss of two barriers and potential loss of the third barrier

Table 4.12-6

Table 4.12-6 provides an **example of an emergency action level (EBD-S) bases document for system malfunction category SU5.** The acronym SU5 is the fifth Unusual Event IC in the System Malfunction recognition category.

NEI 99-01
(NUMARC/NESP-007- Rev. 4

4.12.5 NEI 99-01 (NUMARC/NESP-007- Rev. 4)

Revision 4 to NUMARC/NESP-007 (NEI 99-01) presents the methodology for development of emergency action levels as an alternative to NRC/FEMA guidelines contained in Appendix 1 of NUREG-0654/FEMA-REP-1, Rev.2 "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of nuclear Power Plants, "October 1980 and 10 CFR 50.47 (a)(4). Revision 4 of NUMARC/NESP-007 **enhances Revision 3 (NEI 97-03) by considering the system malfunction initiating conditions and example emergency action levels which address conditions that maybe postulated to occur at nuclear power plants during plant shutdown conditions. Also included are-initiating conditions and example emergency action levels that fully address conditions that may be postulated to occur at permanently Defueled Stations and Independent Spent Fuel Storage Installations.**

Regulatory Guide 1.101, revision 4

4.12.6 Regulatory Guide 1.101

Regulatory guides are issued to describe and make available to the public such information as methods acceptable to the NRC staff for implementing specific parts of the NRC's regulations, techniques used by staff in evaluating specific problems or postulated accidents, and data needed by the NRC staff in its review of applications for permits and licenses. Regulatory guides are not substitutes for regulations, and compliance with them is not required. Methods and solutions different from those set out in the guides will be acceptable if they provide a basis for the findings requisite to the issuance or continuance of a permit or license by the commission.

Prior revisions to Regulatory Guide 1.101 (revisions 1, 2, and 3) stated that "Licensees may use either NUREG-0654/FEMA-REP-1 or NUMARC/NESP-007 in developing their EAL scheme but may not use portions of both methodologies." The staff stated in, Emergency Preparedness Position on Acceptable Deviations from Appendix 1 of NUREG-0654 based upon the Staff's regulatory analysis of NUMARC/NESP-007 that it recognizes that licensees who continue to use EALs based upon NUREG-0654 could benefit from the technical basis from EALs provided in NUMARC/NESP-007. However, the staff also recognized that the classification scheme must remain internally consistent. Licensees can benefit from

The Staff is proposing a revision to RG 1.101 which will endorse NEI 99-01.Licensees would be able to benefit from guidance provided in NEI 99-01 without revising their entire

EAL scheme. This is particularly so in regards to adopting guidance on EALs for cold shutdown and refueling modes of operation or for Independent Fuel Storage facilities. However, the licensee needs to ensure that its EAL scheme remains internally consistent.

Learning Objectives

State the purpose of the Emergency Action Levels.

The purpose of an Emergency Action Level (EAL) is to trigger the declaration of an emergency classification level (ECL), which, in turn, triggers a certain level of emergency response.

List the four Emergency Classification Levels.

Notification of Unusual Event
Alert
Site Area Emergency
General Emergency

List the four documents used to establish Emergency Action Levels.

NUREG-0654/FEMA-REP-1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants,"

Nuclear Utilities Management and Resource Council (NUMARC) issued Revision 2 of NUMARC / NESP-007, "Methodology for Development for Emergency Action Levels"

NEI 99-01 (NUMARC/NESP-007-Rev. 4

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5.1 INTRODUCTION TO TRANSIENTS

Learning Objectives :

1. Given a transient curve:
   - At selected numbered points, explain what caused the parameter to change.
   - At selected numbered areas of the curve, explain why the parameter is trending in that area.
   - State the cause of the transient (initiating event).

2. Given a plant transient scenario, explain the behavior of selected plant parameters, control systems, and equipment for the time designated in the scenario.

5.1.1 Introduction

The following information is presented with the emphasis on analyzing given plant transients with respect to initiating conditions, transient events, end result and conclusions. The transient curves contained in this manual were compiled and analyzed by members of the NRC's Technical Training Division. They were produced from data supplied from the GE BWR/4 Simulator. Specific parameter responses of the simulator were recorded in a data file and converted into graphs with the use of Excel and Claris CAD computer programs. These graphs are **not** to be considered ***Engineering Simulator Model Quality***. Some minor editing of the original curves was performed.

The instructor explanations accompanying these curves are the result of analysis by the TTD Staff during the actual simulator runs and subsequent staff seminars.

Caution is advised when trying to apply these simulator curves to any operating plant. Even relative minor changes in set points, capacities, or piping runs could cause significant differences in indicated responses.

During analysis and study of the curves, the student should concentrate on explaining changes in various parameters caused by the initiating event, subsequent automatic operation of associated control systems or system response to the event. When explaining the identified points always try to relate cause and effect (e.g. power changing from flow change). Don't place too much emphasis on isolated portions of minor deviations in traces unless identified by the instructor.

5.1.2 Transients

In general, the term reactor transient applies to any significant deviation from the normal operating value of any of the key reactor operating parameters. Transients may occur as a consequence of an operator error or the malfunction or failure of equipment. Operational transients are divided into three groups: normal, abnormal and emergency. This division groups transients according to their relative severity on plant operations and safety.

5.1.2.1 Normal Operational Transient

Includes the events that take place during a normal plant startup, shutdown, or load change. These events do not take into effect equipment failure or operator error.

5.1.2.2 Abnormal Operational Transient

Anticipated (Abnormal) transients are deviations from the normal operating conditions that may occur one or more times during the service life of a plant. Anticipated transients range from trivial to significant in terms of the demands imposed on plant equipment. Anticipated transients include such events as a turbine trip, EHC failure, MSIV closure, loss of feedwater flow and loss of feedwater heating. More specifically, all situations (except for LOCAs) which could lead to fuel heat imbalances are anticipated (abnormal) transients.

Many transients are handled by the reactor control systems, which would return the reactor to its normal operating conditions. Others are beyond the capability of the reactor control systems and require reactor shutdown by the reactor protection system (RPS) in order to avoid damage to the reactor fuel or coolant systems.

5.1.2.3 Emergency Operational Transient Accident

An emergency operational transient (accident) is a single event, not reasonably expected during the course of plant operations, that has been hypothesized for analysis purposes or postulated from unlikely but possible situations, and that causes or threatens a rupture of a radioactive material barrier. A pipe rupture is an accident. A fuel clad defect is not.

Design Basis Accident

A design basis accident is a hypothesized accident, the characteristics of which are utilized in the design of those systems and components pertinent to the preservation of radioactive material boundaries and restriction of the release of radioactive materials from these boundaries. The potential radiation exposures resulting from these accidents is greater than any similar accident postulated from the same general assumptions. Design basis accidents include:

- control rod drop accident
- refueling accident
- main steam line break outside the drywell
- loss of coolant accident

5.1.3 Transients Analysis

Transient analysis begins with applying some fundamental rules:

1. Do not try and identify the initiating event.
2. Start with a parameter that you personally know more about.
3. Stay in the same time frame (i.e. do not continue on the same parameter trying to identify all the points prior to going to the next parameter).
4. Make a list of what would cause the parameter of interest to change.
5. Start with the first item on the list and decide what direction and how much of a change you would expect; then look at the change on the curve and see if it is reasonable.
6. If you are not sure continue down the list.
7. Go to the parameter that is affected by the one you have chosen (i.e. power effects pressure, pressure effects steam flow).
8. If you have done everything correctly you will end up with the initiating event.

9. Move to the next time frame and continue the process until all points are identified.

10. Test to see if all points agree with the initiating event.

Figures 5.1-1 represents a blank recorder paper. Each horizontal line is spaced 30 seconds apart and are the same for each parameter. The chart recorder moves from top to bottom, making the top 6 minutes and the bottom time zero.

The following are general notes applicable to all transients unless otherwise indicated:

- Reactor power is from one APRM channel. Assume that if this channel changes the other APRM channels also change.
- Total steam flow is from the FWCS's summations of the individual flow from the flow restrictors on each steam line.
- Total feedwater flow is from the FWCS's summed feed flow from the individual flow measurement devices down stream of the last high pressure feedwater heater.
- Total core flow is the summation of all of the jet pump flows.
- Turbine steam flow is the turbine first stage pressure converted to steam flow.
- Reactor pressure is from one of the reactor vessel pressure monitoring devices.

Transient one, in section 5.2, is a normal operational transient that will be used during the introduction for purposes of indicating how the various parameters change and the use of the rules identified above. ***All other transients covered will fall in the abnormal transient category***

5.1.3.1 Transient Example

Starting with reactor power (rule 2), make a list of things that could change reactor power.

1. Recirculation flow
   a. Pump speed change
   b. Tripping of a recirculation pump

2. Control rod movement
   a. normal rod movement
   b. scram

3. Loss of feedwater heating

4. Pressure increase/decrease

5. Standby liquid control system initiation

Starting with the first item, decide how power should change and how much, then look at the total core flow and APRM curves. At the same or near the same time frame it appears that everything matches, a change in total core flow caused a change in reactor power.

The next step is to move to the next parameter. By applying rule number 7, move to reactor pressure. But, before looking at reactor pressure, decide how pressure should change. If power decreases at a steady rate, pressure should also decrease at that same rate. Look at the pressure curve, it appears that indeed pressure is following reactor power as expected.

Applying rule number 7 again, if pressure changes, the EHC system should respond by adjusting the control and/or bypass valves. Adjusting control valves/BPVs will have an effect on main steam flow. So the next logical parameter is turbine steam flow, and to compare main steam flow to turbine steam flow.

Continuing this process should answer all the questions for the initial change. If you did not start with the parameter that changed first, the above procedure will bring you around to the initiating event. This process is used on each time frame of interest until all points are identified.

A synopsis of transient number one takes place in the following manner:

- Recirculation flow decreases due to the decrease in recirculation pump speed. The decrease in core flow results in a higher void fraction and a negative net core reactivity. The power decrease causes fuel temperature, moderator temperature, and the void fraction to decrease. This continues until the core net reactivity again equals zero. During this transient, the power decrease starts immediately after the core net $\Delta K/K < 0$.

- Power decreases below the steady state value due to the fuel time constant. Before the power generated in the fuel can effect moderator density, fuel temperature must change along with heat transfer to the coolant. The fuel in BWRs responds relatively slow with a time constant between 6 and 10 seconds.

- When reactor pressure decreases, due to the power decrease, the EHC system responds by closing down on the CVs to throttle reactor pressure decrease.

- Reactor water level increases due to the recirculation system removing less water from the annulus than is being supplied by the moisture separator, steam dryers and feedwater.

- Prior to a recirculation flow increase, reactor power increases due to the decrease in feedwater temperature. The increase in reactor power produces an increase in reactor pressure and subsequent increase in steam flow, both total and turbine.

- Following the power decrease with flow, recirculation pump speed is returned to its original value, causing power to increase.

- The increase in reactor power produces a corresponding increase in reactor pressure.

- The increase in reactor pressure is sensed by the EHC system which responds by throttling open the turbine control valves.

- The increase in steam flow is monitored by the feedwater control system along with the level decrease and adjust feedwater flow to maintain reactor water level.

- The decrease in reactor level is caused by the steam flow/feedwater flow mismatch and the recirculation system removing a larger volume of water from the annulus area.

Learning Objectives

6.1 REACTOR VESSELS

Learning Objectives :

1. Describe the internal components and their arrangement that may or may not provide 2/3 core coverage capability following a LOCA.

Introduction

The reactor vessels utilized for a particular product line are dependent on the vintage of the plant, core cooling regulations, type of recirculation system, and technology used during its period of design. The reactor vessel houses the reactor core, serves as part of the reactor coolant boundary, supports and aligns the fuel and control rods, provides a flow path for the circulation of coolant past the fuel, removes moisture from the steam exiting the reactor vessel, limits the downward control rod motion following a postulated failure of a control rod drive housing, and in all cases except the BWR/2 product line provides an internal refloodable volume following a loss of coolant accident.

BWR/2 Reactor Vessel
Figure 6.1-1=====>>>

BWR/2 Reactor Vessel

The BWR/2 reactor vessel, Figure 6.1-1, is an insulated pressure vessel mounted vertically within the drywell and is comprised of a cylindrical shell with an integral hemispherical bottom head. The top head is also hemispherical but is removable to facilitate refueling operations. The base material of the vessel is high strength alloy carbon steel. All internal surfaces including the shell, heads, flanges and attachments are clad with Type 304 stainless steel to a thickness of 0.25 inches. Small nozzles which are not practicable to clad internally with stainless overlay are solid nickel-chromium-iron alloy.

The vessel head is attached to the vessel shell by sixty-four six inch diameter studs that are threaded into bushings in the vessel flange. Spherical washers and closure nuts are match-marked in sets of two and are used in sets. To secure the head to the vessel shell, the studs are elongated by hydraulic stud tensioners which permit the nuts to be turned while the stud is under tension.

Leakage of radioactive coolant and steam between the mating surfaces of the vessel and closure head flanges to atmosphere is contained by two self-energizing O-ring gaskets. These silver plated and polished Ni-Cr-Fe (Inconel) O-rings are approximately 0.50 inches in diameter. The O-rings are designed to have no detectable leakage through the inner or outer member during any reactor operating condition.

Vessel Internals

The major reactor vessel internal components included in this discussion are the core support assembly, core shroud, diffuser, core plate, upper core grid, core spray system sparger, feedwater sparger, steam separators and dryers.

Core Support Assembly

The core support assembly consists of a stainless steel forged ring that is welded to an Inconel segment. The Inconel segment is welded to the lower shell of the vessel. The core support assembly supports the core shroud and separates the recirculation system suction from its discharge.

Core Shroud

The core shroud is supported by the core support assembly. The core shroud along with the core support assembly forms a 17 inch water annulus inside the reactor vessel wall. In addition, a flow barrier is provided by the lower portion of the shroud and the support assembly. This conical skirt, welded to the reactor vessel wall, effectively separates the recirculation inlet core flow from the downcomer annulus flow.

Diffuser

The vessel diffuser is a cylindrical shell hanging downward from a shelf provided by a ring girder. The diffuser contains hundreds of 1.25 inch diameter holes and is approximately eight feet in height. The diffuser serves a two fold purpose; it prevents direct contact of the recirculation flow to the control rod guide tubes and provides a uniform flow of coolant below the fuel orifice region.

Core Plate

The core plate is provided to laterally guide and align the control rod guide tube and fuel support castings. Twelve peripheral fuel assemblies, located outside the control rod pattern are supported vertically by the core plate. These peripheral fuel assemblies rest in a fuel support piece that is welded to the core plate. The core plate prevents recirculation flow from bypassing the fuel assemblies by directing the flow into the control rod guide tube.

Upper Core Grid

The upper core grid or top guide is mounted and supported by twelve brackets inside the shroud. Eight bolts are provided to laterally position and level the top guide. Four hold down bolts attach the top guide to the ledge of the core shroud.

BWR/3 and BWR/4 Reactor Vessels
Figure 6.1-2===>>>>

Core Spray Sparger

Two independent core spray loops are installed in the vessel above the upper core grid (top guide) and within the core shroud. The loops are connected to the Core Spray System which is used for core cooling under loss of coolant accident conditions.

Feedwater Sparger

The feedwater spargers are mounted to the reactor vessel wall in the upper part of the downcomer or annulus region. The spargers, each supplied by one of the two feedwater nozzles, complete a half circle of the vessel interior and discharges water radially inward. A number of 1-inch holes in each sparger permits the cooler feedwater to mix with downcomer recirculation flow before coming in contact with the vessel.

Steam Separator

The steam separator assembly consists of the shroud head and an array of standpipes with steam separators located above each standpipe. The shroud head mates with the core shroud and is bolted to it. The shroud head is a dished unit and forms the cover of the core discharge plenum region. A metal to metal contact seals the separator assembly and the core shroud flange. Operation of the steam separators is identical to that of the separators covered in the systems manual.

Steam Dryer

The steam dryers are required to dry a mass flow of wet steam at 1015 psia and 10 percent moisture by weight to a mass flow of dry steam at 1015 psia and 0.10 percent moisture by weight. The mass flow of steam ranges from zero to 6,933,000 pounds per hour. The dryer assembly is supported by four internal vessel pads. Vertical guides inside the vessel provide alignment during installation, four hold down bolts hold the unit in position.

The dryer assembly is mounted in the vessel above the steam separator assembly and forms the top and sides of the wet steam plenum. Steam that has passed through the separators enters the chevron-type dryer units. A series of troughs and tubes remove the remaining moisture which flows into the downcomer annulus.

BWR/3 and BWR/4 Reactor Vessels

The introduction of the BWR/3 product line (Figure 6.1-2) produced major changes in the reactor vessel design. One of the more important changes was the elimination of the five recirculation loop concept in favor of two loops with jet pumps mounted internal to the reactor vessel. The elimination of five loops removed the recirculation system discharge nozzle penetrations in the vessel bottom head region and reduces the probability of a large break loss of coolant accident. The installation of the jet pumps provides a standpipe effect so the core can be reflooded following a loss of coolant accident and allows better communication between the annulus region and the core region without the need of the recirculation loops.

The BWR/3 product line vessel also included modifications to the feedwater spargers, steam dryers, vessel head, and the cladding overlay. The feedwater spargers increased in number from two to four and contain converging nozzles for better efficiency and extended sparger life. The dryer assembly retained the same operating principle but, added more drying units and was no longer bolted down. The vessel head gained two new penetrations (head spray and spare), in addition to holddown pads to prevent the steam dryer from lifting during system operation. The vessel upper head and nozzle penetration are not clad because it is not needed and the cladding tended to propagate cracks into the base metal on nozzle penetrations.

BWR/4 Advanced Vessel Design

BWR/4 Advanced Vessel Design

Two BWR/4 product line vessels favor the later BWR/5 and BWR/6 design in that they contain separate and independent penetrations for the Low Pressure Coolant Injection (LPCI) mode of the Residual Heat Removal System. The LPCI injection lines penetrate the vessel at four different locations and continue until they penetrate the core shroud.

BWR/5 & BWR/6 Reactor Vessel
Figure 6.1-3 =====>>>

BWR/5 and BWR/6 Reactor Vessel

The BWR/5 product line (Figure 6.1-3) produced changes in the vessel upper head, steam separator and dryer assemblies, instrumentation quadrant taps, and LPCI injection penetrations. The upper vessel head penetrations was reduced from three to only two, one spare and one multipurpose to perform the functions previously performed by two separate penetrations. The steam separator assembly acquired more separating units as did the dryer assembly. The dryer assembly also under went holddown changes to eliminate the problem of ensuring it was disconnected from the core shroud prior to lifting. The LPCI injection penetrations were reduced from four to three.

Summary

The reactor vessels utilized for a particular product line are dependent on the vintage of the plant, core cooling regulations, type of recirculation system, and technology used during its period of design. The reactor vessel houses the reactor core, serves as part of the reactor coolant boundary, supports and aligns the fuel and control rods, provides a flow path for the circulation of coolant past the fuel, removes moisture from the steam exiting the reactor vessel, limits the downward control rod motion following a postulated failure of a control rod drive housing, and in all cases except the BWR/2 product line provides an internal refloodable volume following a loss of coolant accident.

6.2 RECIRCULATION AND FLOW CONTROL SYSTEMS

Learning Objectives

Learning Objectives :

1. Explain the three different types of recirculation loops.
2. Explain valve vs. pump flow control.
3. Explain the thermal shock limitation.
4. Explain the power/flow map.

Introduction
Ask the class for the purpose of recirc system.

Introduction

The Recirculation System provides variable forced circulation of water through the core, thereby allowing a higher power level to be achieved than with natural circulation alone. The Recirculation System, in conjunction with the Recirculation Flow Control System, provides a relatively rapid means of controlling reactor power over a limited range by adjusting the rate of coolant flow through the core.

Control rod movement and recirculation flow adjustment are the two means of controlling reactor power under normal operating conditions. Control rod motion produces local changes in reactivity and neutron flux, while recirculation flow adjustments produce changes in flux across the core without significantly affecting local to average flux values.

An increase in recirculation flow produces an increase in total core flow, or an increase in mass flow rate of subcooled fluid entering the core. This increase in flow suppresses boiling since additional heating is required to reach saturation. The boiling boundary moves upward and the void volume decreases. The resulting positive reactivity increases core power. Power continues to increase until the boiling boundary and void fraction are restored and core reactivity returns to zero. The reverse mechanism occurs on a recirculation flow decrease. In both cases, void fraction changes are transient and void fraction is eventually returned to near the beginning value. The doppler coeffieient produces the slight difference in void fraction because of changes in fuel temperature.

BWR/2
Figure 6.2-1===>>>>

BWR/2

The Recirculation System for BWR/2 product lines, Figure 6.2-1, consists of five parallel piping loops, designated A through E. The pumping loops take suction from the reactor vessel downcomer annulus and discharge to the lower head area beneath the fuel region. The operator adjusts recirculation flow rate by varying the voltage and frequency output of motor generator sets which supply power to the recirculation pump motors.

Objective #1

Recirculation System

The five recirculation pumps, arranged in parallel, take suction from the reactor vessel downcomer annulus through individual outlet nozzles and motor operated suction valves. Pump discharge flow passes through individual motor operated discharge isolation valves and reenters the reactor vessel through five inlet nozzles. A 2-inch line containing a motor operated valve bypasses each pump discharge valve. This path allows a minimum flow during pump starting and provides a small backflow to keep an idle loop warm.

All five recirculation loops are normally in operation, with the pumps at the same speed. Under certain conditions, plant operation is permitted with one loop idle, but not isolated.

Connections to the recirculation system

Various other plant systems that connect to the recirculation system include:

- A 10-inch line joins loop A upstream of the pump suction valve to provide a return flow path to the reactor vessel from isolation condenser A.
- A 3/4-inch line taps off loop A upstream of the pump suction valve to provide a flow path to the sampling system.
- Two 6-inch lines connect to loop B to provide supply and return flow for the Reactor Water Cleanup System.
- Two 14-inch lines connect to loop E to provide supply and return flow for the Shutdown Cooling System.
- A 10-inch line joins the 14-inch shutdown cooling supply line to provide a return flow path to the reactor vessel from isolation condenser B.

The major components of the Recirculation System are discussed in the paragraphs that follow.

Recirculation Pumps

The recirculation pumps provide the driving head for the recirculation system. Each pump is a vertical, single stage, centrifugal pump driven by a 1000 HP, variable speed induction motor. The pumps are powered from individual M/G sets which supply a variable frequency and voltage (11.5 - 57.5 Hz and 460-2300 volts) to change pump speed and flow rate. The flow rate per pump varies from a minimum of 6400 gpm to a maximum of 32,000 gpm.

Each recirculation pump is equipped with a dual seal assembly which contains reactor water within the pump casing and associated controlled leakage lines and allows zero leakage to the primary containment. The assembly consists of two seals built into a cartridge that can be replaced without removing the motor from the pump. Each seal can withstand full pump design pressure so that either will adequately limit leakage if the other fails. A breakdown bushing in the pump casing limits leakage to approximately 60 gpm if both seals fail.

During normal operation, both seals share the sealing work load of the assembly, with approximately a 500 psid pressure drop across each seal. Thus, seal cavity #1 is at reactor pressure and seal cavity #2 is at one-half of reactor pressure. This arrangement is maintained by two internal restricting orifices which control the leakage between the seal cavities, and from cavity #2 to the drywell equipment drain tank (DWEDT), at approximately 0.5 gpm. A flow switch in the controlled leakage line actuates an alarm on seal failure (high flow) or orifice plugging (low flow).

The seal cavities require forced cooling to remove heat generated by friction between the sealing surfaces. The Reactor Building Closed Cooling Water System supplies approximately 25 gpm of water to a heat exchanger surrounding the seal cartridge. Reactor water from the pump cavity passes through a hole in the main pump impeller, around the hydrostatic bearing, and through the shaft to casing clearance to an auxiliary impeller located just below the seal cartridge. The auxiliary impeller forces the seal water through the tubes of the heat exchanger.

BWR/2 Recirculation Flow Control System Figure 6.2-2 ====>>>>

BWR/2 Recirculation Flow Control System

Each recirculation pump is hard-wired to an associated recirculation motor/generator (M/G) set stator (Figure 6.2-2). Since the pumps are driven by an induction motor, pump speed and resulting recirculation loop flow are determined by generator speed (frequency).

Each M/G set consists of a constant speed drive motor, a fluid coupler, a variable speed generator. The speed of the generator is determined by the generator load and the amount of coupling between the drive motor and generator.

Scoop tubes vary the volume of oil in the hydraulic coupler, and thus the amount of torque transmitted from the drive motors to the generators. As a scoop tube is inserted, the volume of oil in the coupler decreases, and both torque transmission and generator speed decrease. Pump speed also decreases, since the pump operates synchronously with the generator. Likewise, oil volume, generator speed and pump speed all increase as a scoop tube is retracted.

The flow control system contains one speed control loop for each of the five recirculation pumps. Manual speed demand signals are sent to the five controllers from two sources during normal operation:

- In the master/manual mode of operation, a single speed demand signal originating in the master controller passes through each M/A transfer station to the speed controllers. All recirculation pumps operate at approximately the same speed, as determined by the master controller. The automatic position of the master controller is not used and the controller is pinned in the manual position.

- In the loop manual mode of operation, the master controller is disconnected, and pump speed is controlled individually by speed demand signals originating in each M/A transfer station.

The speed controllers compare speed demand signals from the M/A transfer stations to speed feedback from the M/G set tachometers. The resulting error signals are supplied to the Bailey scoop tube positioners, which position the M/G set hydraulic coupler scoop tubes. Feedback signals from the scoop tube actuators and speed tachometers stop motion when scoop tube positions are correct.

BWR/3&4
Figure 6.2-3 ====>>>>
Objective #1

BWR/3&4

The recirculation system for BWRs 3&4 (Figure 6.2-3) consists of two piping loops external to the reactor vessel and 20 jet pumps which are internal to the reactor vessel. Each loop has a suction isolation valve, recirculation pump, a discharge isolation valve, instrumentation, and piping connecting to the reactor vessel.

The variable speed recirculation pumps take suction from the reactor vessel annulus region and provide flow to the jet pump riser pipes through the reactor vessel shell. The jet pumps induce additional water from the reactor vessel annulus region into the flow path, increasing system efficiency.

Recirculation System

The major parts of the recirculation system are discussed in the paragraphs that follow.

Suction Valve

There is a suction valve in each recirculation loop between the reactor vessel penetration and the recirculation pump. These motor operated suction valves are used for maintenance isolation of each recirculation pump.

Recirculation Pump

The recirculation pumps are vertical, single stage, centrifugal pumps driven by a variable speed electrical motor. The pumps provide a rated flow of 45,200 gallons per minute each. The speed of the recirculation pumps, and hence the system flow rate, is controlled by the recirculation flow control system.

Discharge Valve

Each recirculation loop contains a motor operated discharge valve located between the recirculation pump and the loop flow measurement device. The valve is remotely operated from the control room using a seal-in to close, throttle to open logic. The discharge valves are automatically jogged open on a pump startup by the recirculation flow control system. Additionally, the discharge valves close as part of the automatic initiation sequence for low pressure coolant injection mode logic of the Residual Heat Removal System to provide an emergency core cooling flow path to the reactor vessel. (See Chapter 6.4)

Jet Pumps

There is a bank of 10 jet pumps associated with each of the external recirculation loops. All jet pumps are located in the reactor vessel annulus region between the inner vessel wall and the core shroud. The jet pumps are provided to increase the total core flow while minimizing the flow external to the reactor vessel.

Each jet pump has a converging nozzle through which the driving flow passes. This creates a high velocity and relatively low pressure condition at the jet pump suction. This low pressure condition creates additional flow from the vessel annulus, called induced flow, through the jet pumps. The combined flows mix in the mixer section of the jet pumps and then pass through the diffuser section. The diffuser section increases the pressure and decreases the fluid velocity. During full power operation approximately one-third of the total core flow comes from the discharge of the recirculation pumps while the remaining two-thirds is induced by the jet pumps.

Recirculation Flow Control

Figure 6.2-4===>>

Recirculation Flow Control

The major components of the recirculation flow control system are discussed in the paragraphs that follow (Figure 6.2-4).

Recirculation Motor Generator Set

The recirculation motor generator set consists of a drive motor, fluid coupler, generator, and the necessary auxiliary components to support motor generator set operation.

The recirculation motor generator set drive motor is a constant speed motor with a horse power rating between 7,000 and 9,000 HP. The drive motor supplies the fluid coupler with motive force through a constant speed input shaft.

The fluid coupler transmits a portion of the drive motor torque to the generator shaft. The amount of torque that is transmitted to the generator is determined by the coupling between the drive motor and generator, which is determined by the amount of oil in the fluid coupler. The quantity of oil in the fluid coupler is regulated by the positioning of a device called a "scoop tube". The greater the quantity of oil in the fluid coupler the greater the coupling between the generator and drive motor. Therefore, the scoop tube position determines the torque transmitted to the generator.

Recirculation Pump Speed Control Logic

The principle of operation in the flow control logic is to set a desired speed, measure the actual speed, compare these signals and produce a control signal used to position the scoop tube to obtain the desired speed. The components performing this function are discussed in the paragraphs that follow.

Master Flow Controller

The master flow controller provides the means of controlling both recirculation motor generator sets from a single controller. Normal operation of the master controller is in the manual mode of operation. By adjusting the manual potentiometer, a demand signal is developed and transmitted to the manual automatic (M/A) transfer station via a dual limiter.

In the automatic mode of operation the electro-hydraulic control system provides the desired main generator set load demand signal. Only one utility, Commonwealth Edison, has operated in the automatic mode and is licensed to do so.

Manual-Automatic Transfer Station Controllers

The M/A transfer station controllers provide the means of controlling the motor/generator set independently or as a paired unit. Similar to the master controller, the M/A transfer stations contain two modes of operation, manual and automatic. Normal mode of operation is both controllers in automatic.

Speed Limiters

There are two speed limiters used in the control logic to limit the maximum and/or minimum speed demand signal according to plant conditions.

The output of the M/A station controller is routed through two speed limiters. The first of these limiters limits recirculation pump speed to a maximum of 28% with the pump discharge valve not full open or feedwater flow less than 20%. This limiter prevents overheating of the recirculation pumps with the discharge valve not open and cavitation problems for the recirculation pumps and jet pumps at low feedwater flow rates.

The second limiter, operational limiter, limits the maximum recirculation pump speed demand to less than that required for approximately 75% power. This limit ensures a sufficient supply of feedwater to the reactor vessel to maintain the required operating level. This limiter is bypassed whenever level is normal or if all reactor feed pumps are in service. The operational limiter is supplied to plants with turbine driven feed pumps. Plants with motor driven feed pumps and an automatic startup of the standby pump do not require a load reduction to maintain level.

Speed Control Summer

The speed control summer, during normal operation, compares the speed demand signal to the actual generator speed and develops an error signal which is sent to the speed controller. The error signal is limited to about 8% of the control band.

Speed Controller

The speed controller establishes and maintains a speed demand signal in accordance with the error signal received from the speed control summer.

Scoop Tube Positioner

The scoop tube positioner converts the electrical input signal, from the speed controller, to a mechanical scoop tube position.

Recirculation Pump Start

Recirculation Pump Start

Figure 6.2-5 ====>>>>

Figure 6.2-5 lists the initial requirements and sequence of events occurring on a recirculation motor-generator startup. Briefly, the drive motor starts if all of the permissives are satisfied. If the scoop tube is in the proper position and the pump is not developing any differential pressure, a 7 second time delay is initiated after which the field breaker closes. During this time delay, the drive motor and generator are accelerating to approximately 12% loaded speed; this corresponds to 40% unloaded speed.

Note on Figure 6.2-4 that when the field breaker is open, the speed control system input to the error limiter is replaced by the signal generator, and the tachometer feedback by the speed controller output. This serves to position the scoop tube to the 40% unloaded position. Excitation is applied to the motor generator set exciter 5 seconds after the drive motor breaker is closed.

Excitation is provided from the 120 VAC startup excitation source. Thus, when the field breaker closes 7 seconds after the drive motor breaker closure, the motor generator set is accelerated to approximately 40% unloaded speed and fully excited to provide the necessary pump breakaway torque.

Once the field breaker is closed, excitation will automatically shift back to the generator output following a 20 second time delay. Since the recirculation pump trip breakers are normally closed, the pump motor is directly tied to the generator output and the recirculation pump starts when the generator field breaker closes.

The 15 second incomplete sequence timer allows time for the pump to "breakaway" and generate >4 psid. As soon as the 4 psid is generated, the incomplete sequence timer is de-energized and the timer resets. When the generator field breaker is closed, the speed control circuits are returned to normal and the pump will runback in speed to the limiter value of 28%, with the discharge valve closed. Following the pump start the discharge valve will then automatically jog open.

Power/Flow Map
Figure 6.2-6===>>>>

Power/Flow Map

The power/flow map (Figure 6.2-6) is a plot of percent core thermal power versus percent of total core flow for various operating conditions. The power/flow map contains information on expected system performance.

28% Pump Speed Line

Startup operations of the plant are normally carried out with both recirculation pumps at minimum speed. Reactor power and core flow follow this line for the normal control rod withdraw sequence with the recirculation pumps operating at approximately 28%.

Design Flow Control Line

This line is defined by the control rod withdraw pattern which results in being at 100% core thermal power and 100% core flow, assuming equilibrium xenon conditions. Reactor power should follow this line for recirculation flow changes with a fixed control rod pattern.

BWR/5-6
Figure 6.2-7===>>>>

BWR/5-6

The recirculation system for BWRs 5&6 (Figure 6.2-7) consists of two piping loops external to the reactor vessel and 20 jet pumps which are internal to the reactor vessel. Each loop has

Objective #1

a suction isolation valve, recirculation pump, flow control valve, a discharge isolation valve, instrumentation, and piping connecting to the reactor vessel.

The two speed recirculation pumps take suction from the reactor vessel annulus region and provide flow to the jet pump riser pipes through the reactor vessel shell. The jet pumps induce additional water from the reactor vessel annulus region into the flow path.

Recirculation System

The major parts of the recirculation system are discussed in the paragraphs that follow.

Suction Valve

There is a suction isolation valve in each recirculation loop between the reactor vessel penetration and the recirculation pump. These motor operated suction valves are used for maintenance isolation of each recirculation pump.

Recirculation Pump

The recirculation pumps are vertical, single stage, two speed, centrifugal pumps. Each is designed to deliver a rated flow of 35,400 gpm at a discharge pressure head of 865 feet. The pumps motors can receive 60 Hz power from 6.9kV buses or 15 Hz power from the associated low frequency motor generator set (LFMG).

In slow speed, the net positive suction head is supplied by the height of water in the reactor vessel. In fast speed, most of the net positive suction head is provided by the subcooling effect of the cooler feedwater flow entering the annulus region where it mixes with the moisture returning from the steam separation stages.

Flow Control Valve

The flow control valve is a 24 inch, stainless steel, hydraulic operated ball valve. The valve is designed to provide a linear flow response throughout its entire stroke (22 to 100% open). The valve is positioned by a hydraulically actuated ram that receives motive power from an independent hydraulic power unit. The actuator is positioned by the Recirculation Flow Control System.

Discharge Isolation Valve

The discharge isolation valve is a 24 inch, motor operated, stainless steel, gate valve. Valve operation is similar to the suction valve.

Recirculation Pump Speed Control

The switchgear in Figure 6.2-8 includes five separate circuit breakers and a low frequency motor generator set. The breakers are interlocked through the pump control logic to prevent supplying the pump motor from both power supplies.

The interlocks provide the proper sequencing of circuit breaker closure during pump startup, speed changes, and shutdown.

The recirculation pump is always started in fast speed because the LFMG does not have the required capacity to supply the necessary breakaway torque.

Recirculation Pump Start Sequencing
Figures 6.2-9====>>>

Recirculation Pump Start Sequencing

To start a recirculation pump in fast or slow, the following permissives (Figures 6.2-9) must be met before the start sequence will initiate:

- Incomplete sequence relay not actuated
- CB-5 racked in
- Flow control valve in manual mode and at the 22% open position
- Suction and discharge valve greater than 90% open
- Vessel thermal shock interlocks satisfied

The incomplete relays activate as a result of the failure to complete the starting sequence. On a slow speed start, the incomplete sequence relay activates if the pump is not operating between 20 and 26% speed or CB-2 does not close within 40 seconds. During a fast speed start, the incomplete sequence relay activates if the pump is not operating at greater than 95% speed after 40 seconds. In addition, loss of logic control power will immediately initiate the incomplete sequence causing CB-1 and CB-5 to trip.

The flow control valve in manual prevents valve cycling during flow changes when the pump starts.

Requiring the flow control valve to be at the 22% position minimizes flow increase during pump start. This reduced flow during pump starts limits thermal stresses on vessel internals, limits power excursions, and allows the pump to reach desired speed faster.

The suction and discharge valves are required to be open during all pump operation for pump protection.

Objective #3

There are three reactor vessel thermal shock interlocks which prevent large changes in water temperature, both in the vessel and recirculation loops. The first of the three interlocks limits the temperature difference between the vessel bottom head drain and the steam dome temperature from exceeding 100 °F. This limit prevents rapid changes in bottom head region water temperature. During periods of low core flow, a stagnant layer of cold water can form in the bottom head region because of the cold control rod drive water. Large changes in recirculation flow (pump start) could sweep away the cold layer, replacing it with hot water creating large temperature gradients on the reactor vessel and its internals. The second temperature interlock limits the difference between the steam dome and the applicable loop suction temperature to less than 50 °F. The 50 °F limit further restricts operation to avoid high thermal stresses on the pump and piping. The third interlock limits the difference between the two loops to less than 50 °F. This limit protects the pump against damage resulting from excessive heatups.

Slow Speed Start Sequence

The recirculation pumps are always started in fast speed. If after the initial start permissive are satisfied, total feedwater flow is greater than 30% and the power level interlock is bypassed, the slow speed start sequence is actuated.

In the slow speed start sequence CB-5 closes, accelerating the pump to 95% speed. At 95% speed CB-5 trips, allowing the pump to coast down. Simultaneously, CB-1 closes, starting the LFMG. When the pump reaches 20-26% speed, CB-2 closes holding the pump at 450 rpm (25% speed, 15 Hz).

Fast to Slow Speed Transfer

Fast to slow speed transfer can be accomplished manually or automatically. Manual transfer from fast to slow is accomplished by depressing both recirculation pump transfer to slow pushbuttons simultaneously. Automatic transfer from fast to slow is accomplished if any of the following conditions are met:

- Feedwater flow less than 30%
- Delta T between steam line and recirculation suction temperature is less than 7 °F.
- Reactor vessel water level 3
- EOC-RPT

Recirculation Flow Control

Recirculation Flow Control

Figure 6.2-10 and 6.2-11

The recirculation flow control system, Figure 6.2-10 and 6.2-11, is capable of varying recirculation flow over a range of 35 to 100% with the recirculation pumps in fast speed or 30 to 40% in slow speed. The major components of the recirculation flow control system include:

- Master Controller
- Neutron Flux Controller

- Flow Controller
- Operational Limiter
- Hydraulic Power Unit
- Valve Actuator

Master Controller

The master controller provide a means of controlling both recirculation flow control valves from a single controller. Controller operation is accomplished in manual or automatic. When in the manual mode, a power demand signal is manually established by the operator with a slide switch on the front of the controller. In automatic mode of operation the controller accepts a load demand signal from the Electro-Hydraulic Control System This signal is then processed throughout the remaining RFC System circuitry to adjust recirculation flow and hence reactor power to balance the load demand. The normal mode of operation on the Master Controller is *MANUAL* mode.

Neutron Flux Controller

The neutron flux controller provides a second means of controlling both recirculation flow control valves from a single controller. In addition, it also provides a stabilizing effect on plant operation by virtue of its power feedback signal. When in manual mode, a flow demand signal is established by the operator. In automatic mode of operation the controller receives a neutron flux demand signal from the master controller which is compared to the reference APRM signal. These two signals are compared to produce an output signal in terms of a flow demand signal. The normal mode of operation for this controller is *MANUAL.*

Flow Controller

The loop flow controllers, one for each loop, provide a means of individually controlling the flow control valves. These controllers can also be operated in manual or automatic. In the automatic mode the controllers receive a flow demand signal from the flux controller and also a flow feedback from the flow element in its recirculation loop suction piping. These two signals are compared and produce an output signal in terms of a flow error signal which is transmitted to its respective hydraulic power unit. Normal mode of operation is automatic.

Operational Limiter

The flow controller output signal is processed through a loop flow limiter. When the recirculation pumps are in *fast* speed the flow limiter limits the signal to a maximum of 48% loop flow (38% FCV position) in the event there is a loss of one reactor feed pump and level cannot be controlled above the low level alarm point.

The purpose of the limiter is to reduce reactor power to within the capacity of one reactor feed pump by closing the FCVs.

Hydraulic Power Unit

The hydraulic power unit is a self contained hydraulic oil system for each recirculation flow control valve. The HPU receives an electric flow signal from the flow controller and converts it into a hydraulic oil pressure signal which then positions the FCV via the valve actuator. FCV position cannot be changed without the HPU in operation.

Figure 6.2-12
Objective #4

Power/Flow Map

A tool used to monitor BWR performance is a power/flow map (Figure 6.2-12). The power/flow map is a plot of core thermal power (in percent of rated) versus core flow rate (also in percent of rated) for various operating conditions. The power /flow map contains information on expected system performance and limits on the recirculation system for operation of the recirculation pumps, jet pumps, and flow control valve.

Summary

The Recirculation System evolved from a 5 loop, with variable speed pumps, system for the BWR/2 to an internal jet pump two loop system for BWRs 3 through 6. The BWR/3 and 4 utilize two variable speed pumps and 20 internal jet pumps to obtain the necessary core flow while minimizing the vessel penetrations. BWRs 5 and 6 also have two independent recirculation loops like the BWR/3 and 4, but vary core flow by throttling flow with a flow control valve.

Learning Objectives :
Viewgraph ====>>>

Introduction

6.3 REACTOR ISOLATION PRESSURE and INVENTORY CONTROL

Learning Objectives :

1. Explain the purpose of the isolation condenser.

2. Explain the operations of an isolation condenser.

3. Describe how the various BWR product lines dissipate decay heat.

Introduction

The discussion in this section deals with the various ways BWR product lines provide pressure and inventory control when isolated from their heat sink. In the event the reactor becomes isolated from its heat sink, some component or system must control reactor vessel pressure and inventory. All BWR product lines have Safety Relief Valves (SRVs) to provide over pressure protection, and hence control reactor pressure. In addition to SRVs, BWRs can control pressure with systems like the isolation condenser, reactor core isolation cooling system, high pressure coolant injecting system, and steam condensing mode of the residual heat removal system. All BWR facilities have a means of providing high pressure makeup water to the reactor vessel to compensate for inventory loss via the pressure control method

In the case of the BWR/2 product line and certain plants of the BWR/3 product line, both of the isolation functions, presure and inventory control, are carried out by a single system called the isolation condenser system. The isolation condenser system draws off reactor steam, condenses the steam in a condenser, and returns the resultant condensate to a recirculation system suction line. By conserving inventory, this system eliminates the need for additional sources of high pressure makeup.

All BWRs of other product lines use SRVs for pressure control and the reactor core isolation cooling system to provide high pressure makeup water to the reactor vessel. Additionally some BWR/4, all BWR/5, and all BWR/6 product line plants have another option available. The steam condensing mode of the residual heat removal system can be used for reactor pressure control. In this mode, reactor steam is reduced in pressure and then condensed in the RHR heat exchangers. Since the resultant condensate can be directed to the RCIC pump suction, both systems can be used together to provide inventory conserving closed loop operation. If the plant is equipped with a system called the high pressure coolant injection (HPCI) System it can also be used to control pressure by aligning the system in the test mode to the condensate storage tank (HPCI operation is discussed in chapter 6.4).

BWR/2 Product Line

BWR/2 Product Line

The BWR/2 product line incorporates both pressure and inventory control into one system, isolation condenser system. The isolation condenser system is a standby, high pressure system that can remove fission product decay heat following a reactor isolation and scram when the main turbine condenser is not available as a heat sink. During reactor isolation, the isolation condenser will control the pressure rise and limit the loss of reactor water, thus avoiding overheating the fuel which could occur through opening of the safety relief valves with no water makeup capability.

Objective #1

The isolation condenser is not intended to be activated fast enough to have any effect upon the initial pressure spikes resulting from the various operational transients (turbine trip, main steam line isolation,...). The system can be activated manually or automatically upon sustained high pressure. The isolation condenser has the capacity to remove reactor decay heat generated a few seconds following a reactor scram from rated power.

Isolation Condenser

Isolation Condenser Figure 6.3-1 ===>>

The isolation condenser, figure 6.3-1, operates by natural circulation. During system operation, steam flows from the reactor, condenses in the tubes of the isolation condenser,and returns (by gravity) to the reactor. The water head, created by condensate flow to the reactor, serves as the driving force for the system.

The isolation condenser is approximately 55 feet long, 12 feet in diameter, and holds approximately 29,000 gallons of water at normal level. Two tube bundles are immersed in water, one bundle at each end of the condenser. The shell side of the condenser vents to atmosphere. Baffles are installed in the shell above the tube bundles to prevent the boiling action from driving shell water out through the shell vents.

Objective #2

The steam inlet valves are normally open so that the tube bundles are at reactor pressure even when in standby. The tube side of the isolation condenser is vented to the main steam line during normal reactor operation. A sustained high reactor pressure automatically puts the isolation condenser system in operation. An automatic initiation will signal the dc motor operated valve on the condensate return line to open and vent valves to the main steam line to close. Steam then flows, under reactor pressure, to the isolation condenser. The steam is routed to both condenser tube bundles where it is condensed by the cooler water in the shell side of the condenser. To obtain the desired flow of condensate from the isolation condenser to the reactor vessel, the normally closed condensate return valve can be throttled by the operator in the control room.

During operation, the water on the shell side of the condenser will boil off and vent steam to the atmosphere. Two radiation monitors are provided on the shell side vent so that in the event of excessive radiation levels, the control room operator will be alerted and can take necessary corrective actions.

Following a reactor isolation and scram, the energy added to the coolant will cause reactor pressure to increase and may initiate the isolation condenser. The capacity of this system is equivalent to the decay heat rate generation 5 minutes following the scram and isolation. With no makeup water, the volume of water stored in the isolation condenser will be depleted in 1 hour and 30 minutes. This allows sufficient time to initiate makeup water flow to the shell side of the condenser.

Makeup water is normally added from the demineralized water makeup system to avoid concentrating radioactive matter resulting from normal water evaporation that occurs in standby mode. Additional water is available from the condensate and fire protection systems.

BWR/3 Product Lines

BWR/3 Product Lines

The BWR/3 product line plants are divided evenly as to the number that utilize the isolation condenser or the newer reactor core isolation cooling system. The previous isolation condenser discussion also applies to the BWR/3 product lines that have isolation condensers. Therefore, it will not be covered again in this section.

Reactor Core Isolation Cooling

The Reactor Core Isolation Cooling (RCIC) system , figure 6.3-2, consists of a steam turbine driven pump capable of delivering water to the reactor vessel at operating conditions. Operation of the RCIC system is fully automatic, or manual by operator selection. The system will start automatically upon receipt of an initiation signal from the reactor vessel low water level sensors. The system will shutdown automatically upon recovery of reactor water level to the high water level set point or upon indication of certain RCIC malfunctions which will trip the turbine.

Water supply to the system is normally from the condensate storage tank through a motor operated suction valve and check valve. This RCIC suction line is maintained flooded in the standby condition to keep the RCIC pump continuously primed. An alternate source of water for the RCIC system is provided by the suppression pool. This source of water would be used if the water level in the storage tank(s) were low or the water level in the suppression pool is too high.

The turbine is driven by steam produced in the reactor vessel and exhausts to the suppression pool, under water. The turbine driven pump supplies makeup water from the condensate storage tank, or alternately from the suppression pool, to the reactor vessel via the feedwater piping. Additional discharge flow paths are provided to allow recirculation to the condensate storage tank for system testing and to provide pump minimum flow to the suppression pool for pump protection. Sufficient capacity is provided to prevent reactor vessel level from decreasing below the top of the core. The system flow rate is approximately equal to the reactor water boil off rate 15 minutes following a reactor scram and isolation.

BWR/4 Product Lines

Objective #3

The BWR/4 product lines all have a RCIC system to provide core cooling makeup water to the reactor vessel under isolation conditions. Later BWR/4 plant designs utilize the RHR system as an additional mode of isolation pressure and reactor water inventory control.

Figure 6.3-3 Steam Condensing Mode

Following isolation of the reactor from its primary heat sink, the residual heat removal system steam condensing mode, figure 6.3-3, is used in conjunction with the RCIC system to remove decay heat and minimize makeup water requirements. Decay heat raises the temperature and pressure of the coolant until the safety relief valves open. As the SRVs continue to remove decay heat in the form of steam, the water level in the reactor vessel would decrease. The RCIC system would be started either manually or automatically to provide makeup water to the vessel under this condition. Shortly after the RCIC system is started, the steam condensing mode can be lined up for operation.

To begin steam condensing operation, the heat exchanger shell side inlet and outlet valves are closed. The service water system supplying the heat exchangers is placed in operation to provide cooling water flow.

The heat exchangers level controller is placed in the manual mode and the level control valve is opened about 10%. The heat exchanger vent valves are throttled open to allow noncondensible gases to vent to the suppression pool. With the pressure controller set at zero, the steam inlet valve is slowly opened. The pressure set point is slowly increased to 50 psig, allowing steam pressure to force water from the heat exchanger to the suppression pool through a motor operated isolation valve. As level decreases, the level control valve is adjusted to maintain desired level. The pressure controller is placed in the automatic mode and pressure is raised to 200 psig.

When RHR system outlet conductivity indicates adequate purity, the flow of condensate is shifted from the suppression pool to the RCIC pump suction. The level control valve is controlled by the lower of two signals, heat exchanger level or RCIC pump pressure. The suction pressure controller is normally set at 45 psig to prevent over pressurizing the RCIC pump suction piping. Level is adjusted to remove the desired amount of decay heat, either to maintain the plant in hot standby or to begin a plant cooldown. As heat exchanger level is decreased, more surface area of the tubes is exposed, thus allowing steam to condense faster. The RCIC pump flow controller is adjusted to equal the rate of condensation, thus reactor water level remains nearly constant. The higher pressure in the RCIC System suction piping closes the check valve in the CST suction line, ensuring that condensate is pumped from the RHR heat exchangers.

Flow path for the steam condensing mode.

The **flow path** for the **steam condensing mode** is as follows: reactor steam passes through the combined RCIC turbine/RHR heat exchanger steam line to the RHR heat exchanger(s); condensate from the RHR heat exchanger(s) is forced (by heat exchanger pressure) to the suction of the RCIC pump; condensate is pumped by the RCIC System to the reactor vessel via the feedwater line. This mode must be manually aligned by the control room operator.

BWR/5 and BWR/6 Product Lines

Objective #3

BWR/5 and BWR/6 Product Lines

The BWR/5 and BWR/6 product lines provide reactor vessel pressure and water level control during isolated conditions with the RCIC system and steam condensing mode of the residual heat removal system. The basic RCIC remains unchanged except for changes in turbine gland sealing and pump discharge. Some BWR/6s were designed to have the RCIC system discharge into the reactor vessel head for better pressure control.

Summary
==========>>>>>>>

Objective #3

Summary

All BWRs provide pressure and inventory control for the reactor vessel. All BWRs are equipped with SRVs to provide over pressure protection. In addition to SRVs Isolation condensers are employed for pressure and inventory control for BWR/2s and some 3s. Reactor core isolation cooling systems are used for BWR/4, 5s, 6s and some 3s for pressure and inventory control when the reactor is isolated. In addition to the reactor core isolation cooling system, some BWR/4s, 5s and 6s are equipped with a steam condensing mode of the residual heat removal system for pressure control.

6.4 EMERGENCY CORE COOLING SYSTEMS

Learning Objectives

Learning Objectives :

1. List the high and low pressure Emergency Core Cooling Systems for the various product lines and explain the purpose of each.
2. List the advantages the BWR/5 and BWR/6 ECCSs have over the BWR/3 and most of the BWR/4 product line ECCSs.
3. Explain how the various types of ECCSs provide core cooling.

Introduction

The Emergency Core Cooling System (ECCS) package provided by a particular product line is dependent on the vintage of the plant and the regulations during that period of time. In all cases there are high pressure and low pressure ECCSs. The Automatic Depressurization System is functionally the same for all facilities.

The purpose of the ECCSs, in conjunction with the containment systems, is to limit the release of radioactive materials to the environment following a loss of coolant accident so that the resulting radiation exposures are within the guideline values of 10 CFR 100.

BWR/2 ECCSs

Objective #1

BWR/2 ECCSs

The BWR/2 product line ECCSs consists of the Isolation Condenser System, Automatic Depressurization System, and the Core Spray System. The three ECCSs operate in various combinations to maintain peak cladding temperature below 2200°F and within the limits specified in 10 CFR 50.46 for any size break LOCA. They must also meet single failure criteria. The Isolation Condenser System is a passive high pressure system which consists of two independent natural circulation heat exchangers that are automatically initiated by high reactor pressure or low-low water level. Isolation Condenser operation is discussed in chapter 6.3.

Automatic Depressurization System

The Automatic Depressurization System (ADS) consists of five automatically activated relief valves that depressurize the reactor vessel during a small break LOCA to permit the low pressure Core Spray System to inject water on top of the core.

The five ADS valves are actuated by low-low-low reactor water level, high drywell pressure, indication that a core spray booster pump has started, and a 120 second time delay. Only four of the five SRVs are required to achieve depressurization in the allowable time period.

Core Spray System
Figure 6.4-1====>>>

Core Spray System

The Feedwater System can supply an adequate amount of cooling water to replace that lost through an extended range of pipe break sizes, providing normal station power and/or offsite power is available. The Core Spray System provides an adequate supply of cooling water independent of the Feedwater System and can be powered from the emergency power system.

The Core Spray System (Figure 6.4-1) is a low pressure system which supplies cooling water after reactor pressure is reduced to 285 psig. This system will prevent the reactor from overheating following intermediate or large breaks. To accommodate some intermediate to small pipe breaks when feedwater is not available, the ADS will depressurizes the reactor thus permitting the Core Spray System to provide core cooling.

The Core Spray System consists of two identical loops Each loop contains two main pumps, two booster pumps, two sets of parallel isolation valves one set inside and the other outside the drywell, a spray sparger, and associated piping, instrumentation and controls. Each pump is rated at 3400 gpm full flow capacity.

Water is supplied to the system from the suppression pool. Also, the Fire Protection System is connected to each of the core spray loops to provide a backup supply of water. Each loop has a test recirculation line to the suppression pool for full flow testing without discharging into the reactor vessel. The piping up to the test valve is carbon steel, designed for 400 psig and 350°F. From the injection isolation valves to the reactor vessel, the piping is stainless steel designed for 1250 psig and 575°F. A core spray filling system maintains the Core Spray System full to preclude any danger of water hammer when the system goes in operation.

The discharge from each of the main pumps flows through a check valve to a common header that supplies water to the booster pumps and a bypass line around the booster pumps. The booster pumps discharge piping contains motor operated isolation valves outside the drywell and air operated testable check valves inside the drywell. Flow from each loop is directed from the pumps through two parallel normally closed motor operated valves, a single line at the containment penetration, two parallel check valves, one locked open manually operated valve and into the sparger.

Both Core Spray Systems and their diesel generators will automatically start upon the detection of one high drywell pressure or one low-low reactor vessel level condition. These conditions

BWR/3 ECCSs

Objective #1

HPCI
Figure 6.4-3 ====>>>

generally indicate a pipe break. The system can also be manually initiated by the control room operators.

BWR/3 ECCSs

The BWR/3 product line high pressure ECCS consists of an ADS system and either a Feedwater Coolant Injection (FWCI) System or a turbine driven High Pressure Coolant Injection System, Figure 6.4-2. The low pressure ECCS consists of two Core Spray System loops and two Low Pressure Coolant Injection loops (either as a separate system or as a mode of the Residual Heat Removal System).

High Pressure Coolant Injection System

The High Pressure Coolant Injection System (HPCI) maintains adequate reactor vessel water inventory for core cooling on small break LOCAs, assist in depressurization of the reactor vessel to allow the low pressure ECCSs to inject on intermediate break LOCAs, and backs up the function of the Isolation Condenser or Reactor Core Isolation Cooling System under reactor isolation conditions.

The HPCI system, Figure 6.4-3, is an independent ECCS requiring no AC power, plant service and instrument air, or external cooling water systems to perform its purposes. The HPCI system consists of a turbine, turbine driven pumps, the normal auxiliary systems required for turbine operation, and associated piping and instrumentation.

The HPCI system is normally aligned to remove water from the condensate storage tank and pump the water at high pressure to the reactor vessel via the feedwater piping. The suppression pool is an alternate source of water with automatic selection on high suppression pool water level or low condensate storage tank water level. A test line permits functional testing of the system during normal plant operation. A minimum flow path to the suppression pool is provided for the HPCI pump in the event the pump is operated with a closed discharge path.

High pressure emergency core cooling for small and intermediate line breaks is provided by the HPCI System. During such breaks, reactor water level could drop to a level where the core is not adequately cooled while the reactor remains at or near rated pressure. With reactor pressure high, the low pressure ECCSs would not be capable of supplying water to the reactor vessel. The HPCI system can supply makeup water to the reactor vessel from above rated reactor pressures to a pressure below that of the low pressure ECCSs injection pressure.

System initiation can be accomplished by automatic signals or manually by the control room operator. Receipt of either a reactor low-low water level or high drywell pressure will automatically start the HPCI system.

Core Spray System
Figure 6.4-4 ====>>>

Core Spray System

The Core Spray System (Figure 6.4-4) pumps water from the suppression pool into the reactor vessel via spray nozzles located on independent ring spargers located within the core shroud above the fuel assemblies. The nozzles are positioned to provide a uniform distribution of coolant to the fuel assemblies.

The Core Spray System consists of two independent loops. Each loop contains a motor operated injection stop valve outside the drywell and a testable check valve plus a manual stop valve within the drywell. Each loop also contains suction isolation valves, test line, minimum flow line and a keep fill line.

The Core Spray System is initiated automatically to provide core cooling upon receipt of either high drywell pressure or low-low vessel water level and low reactor pressure.

Low Pressure Coolant Injection (LPCI) System

Low Pressure Coolant Injection (LPCI) System

Figure 6.4-5 ====>>>

The LPCI system is a closed loop system of piping, pumps, and heat exchangers that are designed to remove post power operation energy from the reactor under both operational and accident conditions. The LPCI system accomplishes this function in several but independent modes of operation.

- LPCI Mode - The LPCI mode operates in conjunction with the HPCI, ADS, and Core Spray systems to restore, if necessary, the water level in the reactor vessel following a LOCA.
- Suppression Pool Cooling Mode - This mode of the LPCI system is manually initiated following a LOCA to prevent pool temperature from exceeding 170°F.
- Containment Cooling Mode - The containment cooling mode permits spray cooling of the drywell and suppression chamber to remove additional heat energy from the primary containment following a LOCA. This is accomplished through the condensation of steam and spray cooling of noncondensibles.

The LPCI system (Figure 6.4-5) includes two separate circulating loops. Each loop includes a heat exchanger, two main system pumps in parallel, and associated piping. The two loops are normally cross-connected by a single header, making it possible to supply either LPCI loop from the pumps in the other loop.

LPCI loop selection logic

Figure 6.4-6 ====>>>>

The LPCI system pump discharge piping is maintained full of water during normal plant operation by a safety system jockey pump or the condensate system.

The LPCI system employs both automatic and manual operation as well as a combination of both, depending on the mode being used. Water is supplied from the LPCI System to the core by injecting into the reactor recirculation system discharge lines.

LPCI Mode

The LPCI mode is established automatically or manually to restore and maintain water level in the reactor vessel to at least two-thirds core height following a LOCA. A LOCA, indicated by vessel level sensing devices or pressure sensing devices in the drywell, actuates the automatic action of the LPCI mode. A combination reactor vessel low-low water level and vessel pressure low or high drywell pressure will provide signals for the following:

- Start LPCI pumps. If normal auxiliary power is available all four pumps start with no time delay. If standby AC power is supplying the bus, pumps A and C start immediately and pumps B and D start after a five second time delay.
- Stop service water pumps, if running.
- Actuate loop selection logic to select the undamaged reactor recirculation loop for injection.
- Opens LPCI heat exchanger valves (inlet, outlet, and bypass).
- Close containment spray valves, if open.

During LPCI operation, suction is taken from the suppression pool and pumped into the core through one of two recirculation loops. Determination of the broken loop is performed by the LPCI loop selection logic, Figure 6.4-6. Four differential pressure switches connected in a one-out-of-two twice logic array determines the preferred loop for injection by measuring the differential pressure between the jet pump risers in both recirculation loops.

A differential pressure greater than 1 psid between loops is indicative of a pipe break. The logic circuit considers the lowest pressure recirculation loop to be broken and ensures LPCI flow is directed only to the good loop by performing the following (assume loop A riser pressure is greater than loop B):

Good loop A

Closes the loop A recirculation pump discharge and discharge bypass valves. Recirc pump A will trip if running. This ensures that LPCI flow is sent directly to the core via the recirc discharge line and jet pumps.

Opens the LPCI injection valves to recirc loop A when reactor pressure decreases to <350psig, to provide maximum LPCI flow to the reactor.

Broken Loop B

Closes the LPCI injection valves to recirc loop B to preclude water loss from the broken pipe.

Ensures that recirc loop B isolation valves remain open to assist rapid depressurization of the reactor coolant system.

When reactor pressure drops to LPCI pump discharge pressure, a check valve in the injection line opens, admitting LPCI flow into the recirc pump discharge line. Although all four LPCI pumps start, only three are needed to deliver design flow. If neither loop is broken, a preselected loop will be used for injection.

BWR/4 ECCSs

Objective #1

BWR/4 ECCSs

The BWR/4 product line high pressure ECCSs consists of a HPCI system and an ADS. The low pressure ECCSs consists of a Core Spray System and a Residual Heat Removal System with a LPCI mode. The high pressure ECCSs are the same as the BWR/3 product line with the exception of the number of SRVs used for automatic depressurization. The Core Spray System is the same as a BWR/3 except for the initiation signals and number of pumps per loop. Initiation signals used for the low pressure ECCSs is high drywell pressure or low-low-low vessel water level. The LPCI mode of the Residual Heat Removal System was divided into two separate and independent loops for most of the BWR/4s due to their higher power density cores and the need to meet the requirements of 10 CFR 50.46.

RHR System
Figure 6.4-7 ====>>>

Residual Heat Removal System (LPCI Mode)

The RHR System, Figure 6.4-7 is a multipurpose system which has five operational modes, each with a specific purpose. The RHR system consists of two separate piping loops, designated system 1 and system 2. Each loop contains two pumps, two heat exchangers and associated piping, valves, and instrumentation.

The low pressure coolant injection (LPCI) mode is the dominate mode and normal valve lineup configuration of the RHR system. The LPCI mode operates automatically to restore and maintain, if necessary, the fuel clad temperature below 2200°F. During LPCI operation, the RHR pumps take water from the suppression pool and discharge to the reactor vessel via their respective recirculation system discharge piping.

The exception to the above mode description is that two of the BWR/4 plants have four separate and independent LPCI loops which discharge directly into the reactor vessel shroud.

BWR/5 & BWR/6

Objective #1

BWR/5 & BWR/6

The BWR/5 and BWR/6 product line ECCSs consists of a High Pressure Core Spray System, ADS, Low Pressure Core Spray System, and LPCI mode of the RHR System, Figures 6.4-8, 9 and 10. Due to the unreliability of the HPCI systems on earlier BWRs, the BWR/5 and 6 were designed with a motor driven high pressure make up system. In addition, the classical 2 divisional power sources was expanded into 3, with division 3 supplying power solely to the HPCS system.

High Pressure Core Spray System

Figure 6.4-8, 9, & 10

The High Pressure Core Spray (HPCS) System provides high pressure emergency core cooling for small, intermediate, and large line breaks. The HPCS System, shown in Figure 6.4-8 is a single loop system and consists of a suction shutoff valve, one motor drive pump, discharge check valve, motor operated injection valve, minimum flow valve, full flow test valve to the suppression pool, two high pressure flow test valves to the condensate storage tank, discharge sparger and associated piping and instrumentation. HPCS takes suction from the condensate storage tank or suppression pool and pumps the water into a sparger located on the upper core shroud. Spray nozzles mounted on the sparger are directed at the top of the fuel assemblies to remove decay heat following a loss of coolant accident (LOCA). The suppression pool is the alternate source of water for the HPCS system.

HPCS initiates automatically on either high pressure in the drywell or low water level in the reactor vessel (level-3). In the event HPCS is any mode other than standby and an automatic initiation signal is received, all valves realign for the injection mode of operation. Normal power for the HPCS system power is provided from the Standby Power System division 3 diesel generator.

Low Pressure Core Spray System

The low pressure core spray system is a single loop system and consists of a suction shutoff valve, one motor driven pump, discharge check valve, motor operated injection valve, minimum flow valve, full flow test valve to the suppression pool, discharge sparger and associated piping and instrumentation. LPCS takes suction from the suppression pool and discharges the water through the core spray sparger ring directly on top of the fuel assemblies. This provides core cooling by removing the decay heat generated from the fuel bundles following a postulated loss of coolant accident.

LPCS, along with other ECCS functions, is automatically initiated by either high pressure in the drywell or a reactor water level 1. The motor operated valves automatically lineup for emergency mode of operation upon a system initiation signal regardless of the alignment unless the system has been removed from service for maintenance by closing the motor operated suction valve.

LPCI Mode of RHR System

The RHR System is a multipurpose system which has five operational modes, each with a specific purpose. The RHR system consists of three separate piping loops, designated A, B, and C. Loops A and B each have a pump and two heat exchangers. Loop C is used exclusively for LPCI mode and is not equipped with a heat exchanger.

The low pressure coolant injection (LPCI) mode is the dominate mode and normal valve lineup configuration of the RHR system. The LPCI mode operates automatically to restore and maintain, if necessary, the fuel clad temperature below 2200°F. During LPCI operation, the RHR pumps take water from the suppression pool and discharge to the reactor vessel inside the core shroud via their own individual penetrations. The LPCI mode initiates automatically on either high pressure in the drywell or reactor vessel water level low (level-1). In the event the RHR system is any mode other than standby and shutdown cooling and an automatic initiation signal is received, all valves realign for the LPCI injection mode of operation.

Summary

The Emergency Core Cooling System (ECCS) package provided by a particular product line is dependent on the vintage of the plant and the regulations during that period of time. In all cases there are high pressure and low pressure ECCSs. The Automatic Depres-surization System is functionally the same for all facilities. All BWRs have a Core Spray System, but only the BWR/5s and 6s have both a high and low pressure Core Spray System. Early BWR/3s were designed with a separate Low Pressure Coolant Injection (LPCI) System. Later BWR/3s changed to a Residual Heat Removal System that consisted of many modes, one of them being LPCI.

High pressure ECCSs did not exists for the early BWRs. Modifications were required by the NRC to upgrade their feedwater pumps. The modifications consisted of having two power sources available. Later BWR/3s were designed with a High Pressure Coolant Injection System that was replaced in the BWR/5 design with a more reliable motor driven High Pressure Core Spray System.

Objective #2
BWR/5 & 6 utilize a more reliable motor driven high pressure ECCS. In addition the LPCI mode of RHR discharges into the reactor vessel through its own penetration

Learning Objectives

Table 6.5-1

Purposes of Containment

Objective # 1 ===>>>

Mark I Containment
Figure 6.5-1 ====>>>

6.5 PRIMARY CONTAINMENTS

Learning Objectives :

1. State the purpose of the primary containment system.
2. Explain the multibarrier, pressure suppression concept as applied to each containment package.
3. Explain the response of the primary containments to a major LOCA.
4. Explain how post LOCA hydrogen gas evolution is controlled for each containment package.

Introduction

The primary containment package provided for a particular product line is dependent on the vintage of the plant and the cost-benefit analysis at the time. During the evolution of the Boiling Water Reactor, three major types of containments were built. The major containment designs are the Mark I, Mark II, and Mark III. Unlike the Mark III, that consists of a primary containment and a drywell, the Mark I and Mark II designs consist of a drywell and wetwell (suppression chamber). All three primary containment designs use the principle of pressure suppression for loss of coolant accidents. For comparison of containments see Table 6.5-1.

Each of the containment designs performs the same functions:

- Condenses steam and contains fission products released from a LOCA so that the off site radiation doses specified in 10 CFR 100 are not exceeded.
- Provides a heat sink for certain safety related equipment.
- Provides a source of water for emergency core cooling systems and the Reactor Core Isolation Cooling System.

Mark I Containment

The Mark I containment design consists of several major components, many of which can be seen in Figure 6.5-1. These major components include the drywell, which surrounds the reactor vessel and recirculation loops; a suppression chamber, which stores a large body of water (the suppression pool); and an interconnecting vent network between the drywell and the suppression chamber. Additionally, there are numerous auxiliary systems associated with the primary containment that are required to meet its intended function.

Component Description

The major components of the primary containment system are discussed in the paragraphs that follow.

Drywell

The purposes of the drywell are to contain the steam released from a loss of coolant accident (LOCA) and direct it to the suppression chamber, and to prevent radioactive materials from passing through its portion of the primary containment boundary.

The drywell is a steel pressure vessel with a spherical lower portion and cylindrical upper portion. The top head closure is made with a double tongue and groove seal which permits periodic checks for tightness without pressurizing the entire vessel. Bolts secure the drywell head to the cylindrical section during conditions that require primary containment integrity. The drywell is enclosed by reinforced concrete for shielding and for additional resistance to deformation and buckling over areas where the concrete backs up the steel shell. Above the foundation, the drywell is separated from the reinforced concrete by a gap of approximately two inches for thermal expansion. Shielding over the top of the drywell is provided by removable, segmented, reinforced concrete shield plugs. In addition to the drywell head, one double door personnel air lock and two bolted equipment hatches are provided for access to the drywell.

Suppression Chamber

The suppression chamber consists of a steel pressure vessel with a toroidal shape (sometimes referred to as a torus) and a large body of water inside the suppression chamber (referred to as the suppression pool). The purposes of the suppression chamber are to condense steam released from a LOCA and to prevent radioactive materials from passing through this portion of the primary containment boundary.

The purposes of the suppression pool are as follows: to serve as a heat sink for LOCA blowdown steam; to serve as a heat sink for safety/relief valve discharge steam and to serve as a heat sink for high pressure coolant injection (HPCI) system and reactor core isolation cooling (RCIC) system turbine exhaust steam; to provide a source of water for the low pressure coolant injection (LPCI) mode of the residual heat removal (RHR) system, core spray system, HPCI system, and RCIC system, The suppression chamber is located radially outward and downward from the drywell and is held on supports which transmit vertical and seismic loading to the reinforced foundation slab of the reactor building.

Access to the suppression chamber is provided through two manways with double gasketed bolted covers. These access ports (manways) are bolted closed when primary containment integrity is required and can be opened only when primary coolant temperature is below 212°F and the pressure suppression system is not required to be operational.

Interconnecting Vent System

The interconnecting vent network is provided between the drywell and suppression chamber to channel the steam and water mixture from a LOCA, to the suppression pool and allow noncondensible gases to be vented back to the drywell. Eight large vent pipes (81" in diameter) extend radially outward and downward from the drywell into the suppression chamber. Inside the suppression chamber the vent pipes exhaust into a toroidal vent header which extends circumferentially all the way around the inside of the suppression chamber. Extending downward from the vent header are ninety-six downcomer pipes which terminate about three feet below the suppression pool minimum water level. Jet deflectors are provided in the drywell at the entrance to each vent pipe to prevent possible damage to the vent pipes from jet forces which might accompany a line break in the drywell. The vent pipes are provided with expansion joints to accommodate differential motion between the drywell and suppression chamber.

Vacuum Relief System

There are two vacuum relief networks associated with preventing the primary containment from exceeding the design external pressure of 2 psi. The first vacuum relief network consists of a set of twelve self actuating swing check valves. These suppression chamber to drywell vacuum relief valves vent noncondensible gases from the suppression chamber to the drywell whenever suppression chamber pressure exceeds drywell pressure by 0.5 psid. The second vacuum relief network consists of a set of two vacuum relief lines from the reactor building (secondary containment) to the suppression chamber. Each line contains a self actuated check valve and an air operated butterfly type vacuum breaker in series. These reactor building to suppression chamber vacuum relief lines vent air from the reactor building to the suppression chamber whenever reactor building pressure exceeds suppression chamber pressure by 0.5 psid.

The suppression chamber to drywell vacuum breakers are remotely tested by using air cylinder actuators. Testing of the suppression chamber to reactor building vacuum breakers is accomplished by testing the equipment which automatically opens the air operated butterfly valves and manually exercising the check valves.

Drywell Cooling System

During normal plant operation there is a closed atmosphere within the drywell and the suppression chamber. Since the reactor vessel is located within the drywell, heat must be continuously removed from the drywell atmosphere. Drywell temperature is maintained between 135°F and 150°F by operating drywell cooling units. Each cooling unit consists of a motor driven fan which blows the existing drywell atmosphere (either nitrogen gas or air) past a heat exchanger which is cooled by the reactor building closed cooling water (RBCCW) system or an equivalent system.

Primary Containment Ventilation System

The purpose of the primary containment ventilation system is to allow for influent air to be brought into the drywell and suppression chamber and for effluent atmosphere to be discharged from the drywell and suppression chamber. This system uses connections to the reactor building heating, ventilation, and air conditioning (HVAC) system for influent air. Connections to the reactor building via the primary containment purge system and to the standby gas treatment system (SGTS) are used for effluent atmosphere. The reactor building HVAC system is used to supply filtered and temperature controlled outside air to the primary containment for air purge and ventilation purposes to allow for personnel access and occupancy during reactor shutdown and refueling operations. The purge exhaust air is either removed by the primary containment purge system and discharged to the atmosphere via the reactor building HVAC system exhaust fans or removed by the standby gas treatment system and discharged to the atmosphere via the plant stack. In either case the effluent is treated prior to release.

Containment Inerting System

The purpose of the containment inerting system is to create and maintain an inerted atmosphere of nitrogen gas inside the primary containment during normal plant power operation. It is necessary to inert the primary containment atmosphere with nitrogen gas in order to maintain the primary containment oxygen concentration less than 4%. Starting with an inerted atmosphere is important in preventing an explosive mixture of hydrogen and oxygen in the primary containment atmosphere following postulated loss of coolant accidents with postulated hydrogen generation.

The containment inerting system consists of a nitrogen (N_2) purge supply and a nitrogen (N_2) makeup supply. The N_2 purge supply is used to initially create the inerted atmosphere in the primary containment. Nitrogen purge systems consist of a liquid nitrogen storage tank, a steam vaporizer (to convert liquid nitrogen to the gaseous state), and associated valving and piping to deliver nitrogen to the primary containment influent ventilation lines. Nitrogen gas is supplied to the primary containment through the purge supply at a rate of 3000-4500 scfm while primary containment atmosphere is discharged to the reactor building HVAC system exhaust ventilation duct or to the standby gas treatment system. This process continues until primary containment oxygen concentration is less than 4%, which takes approximately four hours and requires three to five containment atmosphere volumetric changes.

After the inerted atmosphere has been created, the nitrogen makeup supply is used to continue to supply nitrogen gas as required by temperature changes and leakage. The primary containment is held at a slight positive pressure by the makeup supply and uses the same liquid nitrogen storage tank, its own vaporizer, and valving and piping to deliver nitrogen gas at a rate of <60 scfh to the primary containment.

CAD system Figure 6.5-2 =====>>>>

Objective #4 ===>>>

Containment Atmosphere Dilution System

The purpose of the containment atmosphere dilution (CAD) system is to control the concentration of combustible gases in the primary containment subsequent to a loss of coolant accident with postulated high hydrogen generation rates. The CAD system is capable of supplying nitrogen gas at a rate sufficient to maintain the oxygen concentrations of both the drywell and suppression chamber atmospheres below 5% by volume based on the hydrogen generation rate associated with a 5% metal-water reaction.

The CAD system nitrogen supply facilities shown in some detail in figure 6.5-2, include two separate trains, each of which is capable of supplying nitrogen through separate piping systems to the drywell and suppression chamber. Each train includes a liquid nitrogen supply tank, an ambient vaporizer, an electric heater, a manifold with branches to the primary containment; and pressure, flow, and temperature controls. The nitrogen storage tanks have a nominal capacity of 3000 gallons each which is adequate for the first seven days of CAD system operation. The nitrogen vaporizers use ambient atmosphere as the heat source. Electric heaters are provided for use during cold weather to warm the gas.

Following a LOCA, records are kept of hydrogen and oxygen concentrations and pressures in the drywell and suppression chamber. The CAD system is then operated manually to keep the oxygen concentration <5% or the hydrogen concentration <4% in each volume. Additions are made separately to the drywell and suppression chamber. Manual initiation of the CAD system is calculated to be required about 10 days following postulated design basis LOCA.

When the CAD system is adding nitrogen to the drywell and/or suppression chamber, pressure will increase. Before drywell pressure reaches 30 psig, drywell venting via the standby gas treatment system will be started. Gas releases will be performed periodically and independently from the drywell and suppression chamber.

Releases will be made during periods of the most favorable meteorological conditions at a rate of approximately 100 scfm until the desired volume has been released. Releases will continue over time until primary containment pressure has been reduced to atmospheric. Additions and releases will be conducted at different times.

Objective #3 ===>>>

Containment Response to a LOCA

When the postulated line break occurs, the drywell is immediately pressurized. As drywell pressure increases, drywell atmosphere (primarily nitrogen gas) and steam are blown down through the radial vents to the vent header and into the suppression pool via the downcomers. The steam condenses in the suppression pool which suppresses the peak pressure realized in the drywell. Drywell pressure peaks at 49.6 psig at about 10 seconds following the line break. Noncondensible gases discharged into the suppression pool end up in the free air volume of the suppression chamber which accounts for the suppression chamber pressure increase. As LOCA steam is condensed in the suppression pool, drywell pressure decreases and stabilizes 27 psig while suppression pool temperature reaches 135°F. Drywell pressure decreases to the point that suppression chamber pressure exceeds it by 0.5 psid. This causes the suppression chamber-drywell vacuum breakers to open and vent noncondensible gases back into the drywell to equalize the drywell and suppression chamber pressures.

Low pressure emergency core cooling systems (ECCS) begin pumping water into the reactor vessel, removing decay and stored heat from the core. Water injected into the reactor vessel then transports core heat out of the reactor vessel via the broken recirculation loop. The hot water collects on the drywell floor and then flows into the suppression chamber via the vent pipes, vent header, and downcomer pipes. Thus a closed loop is formed with low pressure ECCS pumps (core spray system and RHR system LPCI mode) pumping water from the suppression pool to the reactor vessel. The water then returns to the suppression pool and the process is repeated.

At about 600 seconds it is assumed that the RHR system would be switched from the LPCI mode to suppression pool cooling. In this mode suppression pool heat is removed via the RHR heat exchangers causing primary containment temperature and pressure to decrease. If necessary, the containment spray mode of the RHR system can be initiated to spray cooled suppression pool water into the drywell and/or suppression chamber atmospheres to control primary containment pressure.

Mark II Containment
Figures 6.5-3 and 6.5.4

Mark II Containment

The Mark II primary containment (figures 6.5-3 and 6.5.4) consists of a steel dome head and either a post-tensioned concrete wall or reinforced concrete wall standing on a base mat of reinforced concrete. The inner surface of the containment is lined with steel plate which acts as a leak tight membrane. The containment wall also serves as a support for the floor slabs of the reactor building and for the refueling pools. The floor slabs are resting on corbels that are formed as part of the containment wall. The refueling pools are integrally connected to, and supported by the concrete containment wall.

The suppression system is the over-and-under configuration. The drywell, in the form of a truncated cone, is located directly above the suppression pool. The suppression chamber is cylindrical and separated from the drywell by a reinforced concrete slab. The drywell is topped by an elliptical steel dome called the drywell head. The drywell inerted atmosphere is vented into the suppression chamber through a series of downcomer pipes penetrating and supported by the drywell floor.

In order to prevent flooding of the drywell during refueling, a bellows type seal is used to seal the space between the reactor vessel and the drywell. The bellows permits free relative movement and offers some restraint to relative lateral displacement of the RPV and the primary containment vessel.

Mark III Containment
Figure 6.5-5

Mark III Containment

BWR/6 product lines use the Mark III containment concept. The Mark III containment is a multibarrier, pressure suppression style containment. The containment structure is similar to a standard dry containment and can be designed as either a free standing steel containment surrounded by a concrete shield building or as a concrete pressure vessel with a liner. The former design is referred to as the reference design while the latter is the alternate. Discussion in this section is limited to the reference design.

The primary containment consists of several major components, many of which can be seen in figure 6.5-5. The drywell is a cylindrical, reinforced concrete structure with a removable steel head and encloses the reactor vessel. It is designed to withstand and confine the steam generated during a pipe rupture inside containment and channel this steam into the suppression pool via the weir wall and horizontal vents. The suppression pool contains a large volume of water to act as a heat sink and water source for ECCSs. A leak tight cylindrical steel containment vessel surrounds the drywell and the suppression pool to prevent gaseous and particulate fission products from escaping to the environment.

Component Description

The major components of the primary containment system are discussed in the paragraphs that follow.

Drywell

The drywell is a cylindrical reinforced concrete structure with a removable vessel head to allow vertical access to the reactor vessel for refueling or maintenance. The drywell is designed for an internal pressure of 30 psig, an external pressure of 21 psig, and an internal temperature of 330 °F. However, a high degree of leak tightness is not a requirement since the drywell *is not* a fission product barrier.

Large diameter horizontal vent openings penetrate the lower section of the drywell cylindrical wall to channel steam from a LOCA into the suppression pool.

Purpose of Drywell for Mark III

The main function of the drywell is to contain the steam released from a LOCA and direct it into the suppression pool. Other functions of the drywell include:

- provide shielding to reduce containment radiation levels to allow normal access.
- provide structural support for the upper pool.
- provide support structure for work platforms, monorails, and pipe supports.

Horizontal Vents and Weir Wall

The weir wall forms the inner boundary of the suppression pool, and is located inside the drywell. It is constructed of reinforced concrete approximately two feet thick and lined with a steel plate on the suppression pool side.

Since the weir wall forms the inside wall of the suppression pool, it contains the pool and allows channeling the steam released by a LOCA into the suppression pool for condensa-

Auto Dump
LOCA signal AND
1. Low-Low s/p level OR
2. 30 min Timer OR
3 Manual

tion. The weir wall height is 25 feet and allows a minimum freeboard of 5 feet 8 inches. This freeboard is sufficient height to prevent the suppression pool from overflowing into the drywell.

The Mark III arrangement uses horizontal vents to conduct the steam from the drywell to the suppression pool following a LOCA. Figure 6.5-6 shows an enlarged horizontal and vertical section of vents. In the vertical section, the drywell wall is penetrated by a series of 27.5 inch diameter horizontal vent pipes. There are 3 rows of these horizontal pipes at levels of 7.5, 12 and 16.5 feet below the surface of the suppression pool. The total pool depth is approximately 20 feet. The horizontal section is a partial view of the 40 column of vents, vent annulus, and weir wall.

Any buildup of drywell pressure forces the water down in the annulus. The higher the pressure in the drywell the greater the depression and the number of vents that will be uncovered.

Containment

The containment is a free standing cylindrical steel pressure vessel that surrounds the drywell and suppression pool to form the primary leak tight barrier to limit fission product leakage during a LOCA. By design the containment will not leak more than 0.1% of the containment volume in 24 hours at a pressure of 15 psig.

Among the postulated LOCAs, some accidents may require flooding the containment to remove fuel from the reactor and effect repairs. Although it is anticipated that for most accidents, defueling of the reactor will be accomplished by normal procedures and equipment, as a contingency to cover undefined damage resulting from a LOCA, the containment can be flooded to a level 6 feet 10 inches above the top of the active fuel in the core.

Upper Pool

The containment upper pool walls are above the drywell and within the containment column. The pool is completely lined with stainless steel plates and consists of five regions:

- moisture separator storage
- reactor well
- steam dryer storage
- temporary fuel storage

- fuel transfer region

The upper pool provides radiation shielding when the reactor is operating, storage for refueling operation, and a source of water makeup for the suppression pool following a LOCA.

CCGC system
Figure 6.5-7 ===>>>>

Objective #3 & 4 ===>>>

Combustible Gas Control

To ensure containment integrity is not endangered because of the generation of combustible gases following a postulated LOCA, the containment is protected by a collection of systems called the containment combustible gas control system (CCGC system).

The CCGC system, figure 6.5-7, prevents hydrogen concentration in the primary containment from exceeding the flammability limit of 4% (by volume). The system is capable of mixing the atmosphere inside the drywell with that inside containment following a LOCA. When the drywell hydrogen concentration begins to increase, the drywell mixing compressors are started manually by the control room operator. Air from the containment is pumped into the drywell increasing drywell pressure. The increase in drywell pressure depresses the annulus water uncovering vents and allowing the drywell atmosphere to mix with the containment.

1150°F Temperature for Hydrogen-Oxygen reaction

reaction is due to Temperature increase

While drywell mixing continues following a LOCA, hydrogen continues to be produced. Eventually, the 4% limit is approached in the containment, requiring the hydrogen recombiners and hydrogen ignition system to be manually placed in operation. The recombiners are located in the containment upper region. Air flow through the recombiner is designed to process 100 cfm of containment air, heating it to 1150°F. The heated air leaving the heater section is mixed with containment atmosphere to limit the outlet temperature to approximately 50°F above ambient.

The hydrogen ignition system consists of hydrogen ignitors distributed throughout the drywell and containment. The ignitors burn the hydrogen as its evolved to maintain the concentration below detonable limits.

A small line, connecting the drywell with the shield building annulus, is used during reactor startup and heatup. Drywell pressure is vented to the annulus through the bleedoff and backup purge line. This venting can support plant heatup at the design rate of 100 °F/hr. If hydrogen recombiners are not available subsequent to a LOCA, the drywell bleedoff valves may be opened for backup purging. This flowpath allows about 100 cfm of air from the drywell to enter the shield building annulus where it is removed and then later processed by the standby gas treatment system.

Summary

The primary containment package provided for a particular product line is dependent on the vintage of the plant and the cost-benefit analysis at the time. During the evolution of the boiling water reactor, three major types of containments were built. The major containment designs are the Mark I, Mark II, and Mark III. Unlike the Mark III, that consists of a primary containment and a drywell, the Mark I and Mark II designs consist of a drywell and wetwell (suppression chamber). All three primary containment designs use the principle of pressure suppression for loss of coolant accidents. For comparison of containments see table 6.5-1.

Objectives View graph

6.6 ROD CONTROL SYSTEMS

Learning Objectives :

1. State the purpose(s) of the Reactor Manual Control System, Rod Worth Minimizer, Rod Sequence Control System, Rod Block Monitoring System, and the Rod Control and Information System
2. Explain how control rod motion is achieved with the Reactor Manual Control System and the Rod Control and Information System.
3. State the major advantages the Rod Control and Information System has over the Reactor Manual Control System.
4. List the types of rod blocks and when they are in effect for the Rod Worth Minimizer, Rod Sequence Control System, and the Rod Block Monitoring System.

After presenting lesson objectives ask the class for the purpose(s) in objective #1

Place view graph of purpose(s) on other white board and then fill it in with the BWRs and their systems that perform that purpose.

Introduction

The Rod Control Systems for BWR/2 through BWR/5 product lines utilize a collection of systems to accomplish the same purposes as the Rod Control and Information System supplied with the BWR/6 product line. The collection of systems used include the Reactor Manual Control System, Rod Worth Minimizer System, Rod Sequence Control System, and the Rod Block Monitoring System. The purposes of the Rod Control System's are:

- Provide a means of changing core reactivity to change reactor power level and control flux distribution.
- Enforce rod patterns to limit rod worth and reduce the effects from rod drop accident or rod withdraw error.

BWR/2 Product Line

BWR/2 Product Line

The BWR/2 product lines control rod worth and provide a means of changing core reactivity with the Reactor Manual Control System and the Rod Worth Minimizer System. Discussion of these systems are found in the paragraphs that follow.

Figure 6.6-1 ====>>>

Reactor Manual Control System

The Reactor Manual Control System (Figure 6.6-1) consists of the switches, relays, interlocks, alarms, and electrical equipment necessary to result in control rod movement. The RMCS provides the necessary sequence and timing signals to the directional control solenoid valves of the control rod selected for movement. Normal control rod movement is one notch at a time through the timing sequence, but continuous movement controls are provided. The basic inputs to the RMCS are manual via the rod select pushbuttons and rod movement control switches. Interlocks are provided to block the selection and/or movement of a control rod if plant conditions are abnormal. The major components of the Reactor Manual Control System are discussed in the paragraphs that follow.

Rod Select Matrix

The manual rod selection capability is provided by pushbutton type switches, one for each rod, arranged to the approximate geometry of the core. The push buttons are wired so that when one switch is depressed, control power is removed from all other rod select pushbuttons.

Rod Selection Relays

Energization of the rod selection relay indicates that the rod select pushbutton request has been honored and the control rod is allowed to selected for movement. For the selection to be honored select block interlocks must be satisfied.

Rod Control Relays

The rod control relays allow the request for rod movement to be transmitted from the rod movement control switches to the timer logic, if certain permissives are met. These permissives are termed "rod blocks" and are either insert or withdraw blocks.

Timer Logic

The timer logic provides the required signals to the directional control solenoid valves in the proper sequence and timing to cause the selected control rod drive to respond as requested by the operator.

Rod Movement Control Switches

Control rod drive movement request is accomplished through the use of two control switches, the control rod movement control switch and/or the emergency in notch override switch.

The control rod movement control switch is a three position switch; rod in, off, and rod out notch (spring return to off). Through the use of this switch the operator can initiate notch in and notch out cycles. Notch movement means moving a control rod from one even position indication to the next. If the switch is held in the rod out position, the control rod will complete one notch out cycle and stop. If the switch is held in the rod in position the control rod will continuously drive in until released.

The emergency in notch override switch allows the operator to make a continuous rod withdrawal when used simultaneously with the rod movement control switch. The emergency in position is provided to allow control rod selection if the timer logic is not available or wanted.

Rod Worth Minimizer

RWM
Figure 6.6-2 ===>>>

Table 6.6-1 ===>>>

The Rod Worth Minimizer (RWM), Figure 6.6-2, serves as a backup to procedural controls to limit rod worth during low power operation so that the postulated rod drop accident will not exceed the allowed limit of 280 calories/gram. Table 6.6-1 provides additional information for other cal/gm values. Rod movement sequences are developed to limit rod worth to a level below which, if a rod drop accident were to occur at a free fall rate limited by the velocity limiter, the enthalpy from the transient would be less than 280 calories/gram. Figure 6.6-3 shows rod worth curves relative to the danger level for unrestrained rod movement (curve A) and RWM restrained movement (curve B). Due to lower rod worth at power, the RWM is not needed to limit rod worth above 20% power. The major components of the RWM are the computer program and the operator's display panel.

The RWM is a computer monitoring system which minimizes control rod reactivity worth by blocking rod movement if the existing control rod pattern deviates from a specific sequence. The sequences are developed by the plant nuclear engineers and loaded into the RWM memory. Actual rod positions are obtained, for comparison to the sequence, from the Rod Position Information System.

Operating Sequence

The Rod Worth Minimizer program contains an operating sequence which is loaded into the computer memory. The operating sequence is a schedule to be followed by the plant operator when withdrawing or inserting control rods. The sequence identifies the control rod by XX-YY coordinates and the positions to which each rod should be withdrawn in going from shutdown to full power. When going down in power, the rods are inserted in the reverse order of their withdrawal. The operating sequence is sequentially subdivided into rod groups.

Each rod group consists of a number of specified control rods and a set of insert and withdraw position limits that apply to each rod in the group. The groups are numbered in the order in which they are to be withdrawn when going up in power. Each sequence generally begins by withdrawing approximately half the rods in the core to full out. Under cold conditions, this brings the reactor to the point of criticality and to heating power. The fully withdrawn control rods are distributed in a checker board (black and white) pattern. The remaining rods are subsequently withdrawn to either full out or intermediate positions in the order specified by the sequence.

Notch Error

All rods in groups higher than that in which the black and white pattern is achieved have notch control restraints superimposed on the normal group limits. This means that in addition to remaining within the groups limits, any rod contained in one of these notch control groups must also remain within one notch position of every other rod in the same group.

A notch error occurs whenever the reactor is operating in a rod group higher than that in which a black and white pattern is achieved and notch limits are violated (rods in a group are more that one notch apart).

Low Power Set Point

The low power setpoint is the core average power level below which the Rod Worth Minimizer program is active in forcing adherence to the operating sequence of rod withdrawals or insertions. When the core power level is above the low power setpoint, the program does not impose any rod blocks as a result of rod movement by the operator. The low power setpoint is set above the level of required enforcement (20% power) and is sensed by both total steam flow and total feedwater flow being greater than 30% of rated power.

Withdraw Error

A withdraw error can occur either when a rod contained in the current group or any lower group is withdrawn past the withdraw limit for the group, or if a rod contained in a group higher than the current group is withdrawn past the insert limit for the higher group.

Insert Error

An insert error occurs when a rod contained in the current group is inserted past the insert limit for this group, or if a rod contained in a group lower than the current group is inserted past the withdraw limit for the lower group.

Select Error

A select error occurs whenever the operator selects a rod other than one contained in the current rod group. The select error provides the operator with warning that he has selected a rod, which if moved, will create an insert or withdrawal error.

Operation

Control rods are withdrawn according to the operating sequence. The Rod Worth Minimizer sequence restraints require that the rod groups be pulled in sequential order to specific group limits. The control rods within a group may be pulled in any order. Some flexibility is permitted by allowing two insert errors before rod blocks are applied. One withdrawal error will cause a rod withdrawal block. The rod blocks are normally applied so that only rod movements to correct errors are allowed. Forcing the operator to make the necessary corrections before permitting further rod movement. Once the black and white pattern is obtained notch limits must be observed in addition to group limits. The rods within the group must remain within one notch position of every other rod in the group. A notch error exists if notch limits are violated resulting in rod blocks being applied forcing the correction of the notch error before rod movements can continue.

BWR/3 Product Line

BWR/3 Product Line

The BWR/3 product line utilizse the same systems as the BWR/2 product line plus one additional system, Rod Block Monitoring System, for power operation greater than 30% power. The Rod Block Monitoring System prevents the operator from exceeding thermal hydraulic limits in a local region of the core for a single rod withdrawal error from a limiting control rod pattern. A limiting control rod pattern is defined as a pattern which results in the core being on a thermal hydraulic limit.

Rod Block Monitoring System

The Rod Block Monitoring (RBM) system is designed to prevent local fuel damage by generating a rod withdrawal block under the worst permitted LPRM detector bypass and failure conditions and under the worst single rod withdrawal error when starting from any permitted power and flow condition. This system prevents overpower around a control rod by blocking the withdrawal of that rod. This prevents: the local fuel bundles from approaching MCPR limits; local power from grossly exceeding the total core power limit; and local fuel damage, by supplementing the APRM trip functions.

The system monitors local power by generating a signal from the LPRMs in the four strings which surround the rod selected for movement. The RBM function, by analysis, is not required below 70 percent power. However, it is used whenever the reactor power is above 30 percent as indicated on the APRM channel which is assigned as a reference to each RBM Channel. The RBM setpoints are derived from the results of various transient analyses which are performed for each fuel cycle.

The system receives a "rod select" signal from the Reactor Manual Control system. It routes the LPRM outputs from the adjacent LPRM assemblies to the averaging circuit. The system increases the gain of the averaging circuit until its output equals, or exceeds, the reference APRM signal. The system then compares this signal to a flow-biased reference signal. A rod withdrawal block is generated if the averaged LPRM signal raises above the flow-biased trip reference signal.

Figure 6.6-4

Typically, there are two RBM channels. Each channel receives inputs from specified levels (A and C; or B and D) of LPRM detectors. There are three parallel trip reference levels which will be used for generating the rod block setpoints, as shown in Figure 6.6-4.

ARTS Program

General Electric Nuclear Energy has instituted a new program identified as Average Power Range Monitor (APRM), Rod Block Monitor (RBM), and Technical Specifications Improvements. **This program is called the ARTS program. The objectives of the ARTS program are to:**

- **Increase plant operating efficiency.**
- **Update thermal limits requirements and administration.**
- **Improve plant instrumentation re-sponses and accuracy.**
- **Improve the man/machine interface involved in plant operation.**

Improvements

General Electric maintains that the above objectives are attained by making the following improvements:

- Implementing a power dependent minimum critical power ratio (MCPR) limit similar to that used by BWR/6.
- APRM trip setdown requirement is replaced by more meaningful limits to reduce the need for manual setpoint adjustments and to allow direct limits administration.
- Flow-biased RBM trips are replaced with power dependent trips.
- RBM inputs from the LPRMs are assigned to improve the response characteristics and to produce trip percentage increases of initial signal, Figure 6.6-5 & 6.6-6.
- Rod withdrawal error analysis is performed to more accurately reflect the actual plant conditions.

With the introduction of ARTS, the APRM setpoint setdown factor is removed.

BWR/4 & BWR/5 Product Lines

BWR/4 and BWR/5 Product Lines

BWR/4 and BWR/5 product lines added an additional system to the already existing systems being used to control rod movement by imposing rod block trip signals. The introduction of the BWR/4 product lines with a higher power density core required further studies in limiting rod worth. The studies indicated a new system was needed to backup the Rod Worth Minimizer because:

- The RWM had a poor reliability record.
- The RWM could fail in an unsafe manner.
- The RWM is easily bypassed.

The new system designed to be a backup to the RWM is the Rod Sequence Control System (RSCS).

Rod Sequence Control System

The Rod Sequence Control System (RSCS) restricts rod movement to minimize the individual worth of control rods to lessen the consequences of a rod drop accident. Control rod movement is restricted through the use of rod select, insert, and withdraw blocks. The RSCS is a hardwired, redundant backup system to the RWM. It is independent of the RWM in terms of inputs and outputs but the two systems are compatible.

The RSCS operation is divided into two modes of operation, with the black and white rod pattern being the division point. At less than a black and white rod pattern, the sequence control mode controls rod movement from rod full-in to the black and white rod pattern by imposing select blocks. The group notch control mode controls rod movement from the black and white rod pattern to 30% power by imposing rod withdrawal and insert blocks.

Sequence Mode Selector

The Sequence Control Mode controls rod movement from rods full in to the black and white rod pattern by imposing rod select blocks. These rods are divided into two rod groups which are compatible with Rod Worth Minimizer rod groups. From an all rods full in condition, the operator may choose either of the two groups to begin movement. Once the operator begins to withdraw the first rod in that group, the logic will not allow selection of any rods but those in the chosen group, until all rods in that group are moved to the full out position. When all rods in the second group are moved full out, the Rod Sequence Control

System will move into Group Notch Control.

The sequence control logic makes decisions on the basis of inputs from the Control Rod Drive System. It provides only full in and full out position information for each control rod drive mechanism to the Rod Sequence Control System. This information is derived from redundant switches in the control rod drive mechanism position indicating probe and is not used for digital display or by the Rod Worth Minimizer.

The sequence control logic will not allow selection of out of sequence control rods for movement.

Group Notch Control Mode

The Group Notch Control Mode controls rod movement from the black and white pattern to the 30% power bypass, by imposing rod withdrawal and insert blocks. All control rods are assigned to notch control groups which are compatible with Rod Worth Minimizer rod groups.

Group notch control logic requires that all rods within a notch control group must remain within one notch. Once a rod is moved in either direction in a notch group, rod blocks are imposed on; (1) the initially moved rod to prevent further movement in the same direction, and (2) all other rods in that group to prevent movement in the opposite direction. After the initial movement, the logic is reset whenever all rods in the notch group are again at the same position. The logic consists of a set of memory units, one for each notch group. The memory units track the relative position of the rods in each group by sensing the rod selected, direction of movement requested, and the occurrence of the Reactor Manual Control System timer settle function. The logic output signals are applied to the Reactor Manual Control System as withdraw or insert blocks.

Comparison to RWM

The Rod Sequence Control System restraints are designed to be compatible with those of the Rod Worth Minimizer. Several differences in philosophy between the two systems are outlined below:

The Rod Worth Minimizer is more restrictive in the sequencing of rod movements.

The Rod Worth Minimizer applies restraints only after the operator has deviated from the operating sequence. The Rod Sequence Control System restraints are applied so that the operator is not allowed to deviate.

The Rod Worth Minimizer can be entirely bypassed manually by the operator. The Rod Sequence Control System has only limited manual bypass capability.

The Rod Worth Minimizer is computer software and can be changed by a programmer. The Rod Sequence Control System is completely hardwired.

Bypass Capability

The Rod Sequence Control System is not required to limit rod worth at greater than 20% reactor power. A system bypass signal is generated at a conservative level of 30%, as measured by a pair of pressure sensors which monitor the main turbine first stage pressure.

The circuitry does allow certain bypass capability. In the Sequence Control logic, the full in or full out position for each rod can be bypassed. This is necessary for certain surveillance tests. In the Group Notch control logic, each notch group memory has a reset button which will reset the memory regardless of the previous latch states.

NEDE-24011-P

In a letter of August 15, 1986 from T.A. Pickens, Chairman of the BWR Owners Group (BWROG), an Amendment 17 to General Electric Topical Report NEDE-24011-P (GESTAR II) was proposed and agreed to by the NRC. This submittal was a request to eliminate the required use of the Rod Sequence Control System (RSCS). The proposal stated better computers used by RWMs, lower peak fuel enthalpy from a rod drop accident, an existing NRC probability study demonstrating an extremely low probability for an event exceeding fuel damage criteria (10^{-12}), and RSCS elimination would reduce operational complexity (ATWS events). To date some plants, not all, have elected to eliminate the RSCS.

BWR/6 Product Line

BWR/6 Product Line

The BWR/6 product line controls rod movement and rod worth with the Rod Control and Information system (RSCS). RC&IS consists of the electronic circuitry, switches, indicators, and alarm devices necessary to achieve control rod manipulation. To prevent inadvertent operator errors, reactor core performance and control rod positions are constantly monitored by systems that either give an alarm demanding operator attention or completely block rod movement until the error has been corrected. *The RC&IS includes interlocks that inhibit control rod moment, but does not include any of the circuitry or devices used to scram the reactor.*

RC&IS
Figure 6.6-7 ===>>>

RC&IS is comprised of four subsystems, (Figure 6.6-7):

- Rod Interface System (RIS)

- Rod Action Control System (RACS)
- Rod Gang Drive System (RGDS)
- Rod Position Information System (RPIS)

The RC&IS can be operated in either the gang drive or the individual drive mode. In the gang mode up to four control rod can be positioned at once. Discussion of the major components of the RC&IS are discussed in the paragraphs that follow.

Rod Interface System

The Rod Interface System (RIS) is a digital, time multiplexed, fixed program, special purpose computer comprised of an operator control module, rod display module, and auxiliary select module. Data to be displayed arrives at the RIS in the form of several multiplexed words originating in the RACS, Rod Action Drive System (RADS), and the Neutron Monitoring System. Several multiplexed words are entering every millisecond and are used to update the memory so that it is never greater than a few milliseconds old. Independently, the memory is being searched and transformed into the correct display for the operator.

Rod Action Control System

The Rod Action Control System (RACS) consists of two redundant channels. Each channel includes the rod pattern control function, rod motion inhibit logic, and the directional control valve timing functions. RADS receives requested control rod motion signals from the RIS and after checking for the correct rod pattern sequence and interlocks generates a motion command and hydraulic control unit identity signal for the RGDS.

Rod Pattern Controller

The purpose of the rod pattern controller is to limit the worth of any control rod to minimize the undesirable effects resulting from a rod drop accident or rod withdrawal error. The rod pattern controller is a dual channel system designed as a safety related system to enforce procedural controls by applying rod blocks before any rod motion can produce high rod worth patterns. Rod pattern controllers are hard wired and are not programmable except through the use of new electronic cards.

The rod pattern controller continuously monitors the operator's request for rod motion, checks the request against built in criteria and, if necessary, blocks the RC&IS from carrying out the request.

Rod Gang Drive System

The rod gang drive system contains an analyzer section that compares motion and hydraulic control unit identity signals from two channels of the RACS. A disagreement between the signals is displayed on a fault map for operator information. If the signals agree, one signal is stored in memory while the other is sent to the transponders of the hydraulic control units as an enable signal. Transponders, one for each hydraulic control unit, contains circuits that decode the motion command signals and compare the identity address to their own. If the identities match, the hydraulic control unit responds to the operation action code for rod movement. The transponder acknowledge the command signal by sending a signal back to another comparator in the RGDS where the requested and operation being performed. If the identity and operation code do not agree, the operation is terminated and annunciated.

Summary

The Rod Control Systems for BWR/2 through BWR/5 product lines utilize a collection of systems to accomplish the same purposes as the Rod Control and Information System supplied with the BWR/6 product line. The collection of systems used include the Reactor Manual Control System, Rod Worth Minimizer System, Rod Sequence Control System, and the Rod Block Monitoring System.

Learning Objectives Viewgraph =====>>>>

6.7 BALANCE OF PLANT SYSTEM

Learning Objectives :

1. Explain how water level is controlled with motor driven feedwater pumps.
2. Explain how and why pump runout protection is provided for motor driven feedwater pumps.
3. Explain how some of the feedwater control systems minimize level overshoot.
4. List the major differences found in condensate and feedwater systems.

Introduction

The discussion in this section is directed toward the condensate and feedwater system and the feedwater control system. Keeping in mind that the condensate and feedwater system is designed by the architectural engineer in concurrence with the utility; very few are the same. However, you will discover that all systems must have a means of delivering the water at sufficient pressure and volume to maintain reactor vessel water level during normal system operation. In addition, the condensate and feedwater system will cleanup and preheat the water prior to delivering it to the reactor vessel.

The feedwater control systems consists of two basic types with small variations to account for the specific condensate and feedwater system being controlled.

Condensate and Feedwater System

The two most common condensate and feedwater systems used differ in the type of feed pumps, feedwater heater arrangement, and the means of filtering and cleaning up the water.

Early Condensate and Feedwater System

Figure 6.7-1 ===>>>

Early Condensate and Feedwater System

The condensate and feedwater system, Figure 6.7-1, is an integral part of the plants conventional regenerative steam cycle. The steam exhausted from the three low pressure turbines is condensed in the main condenser and collected in the condenser hotwell, along with various equipment drains. The condensate is removed from the hotwell by three of the four condensate pumps. The fourth pump is a standby pump with an automatic start feature if one of running pumps should trip. The condensate pumps provide the driving force for the condensate which flows through the steam jet air ejector (SJAE) condensers and gland seal leak off (GSLO) condensers; to perform a heat removal function. At this point the condensate is directed to the condensate demineralizers to filter and demineralize the condensate. After the demineralizers, booster pumps increase the driving force for the condensate flowing through three parallel strings of low pressure feedwater heaters.

Each heater string is rated for 33% flow. Isolation of a string requires routing the flow through the bypass line around the heater string. This type of heater string arrangement yields a large and sudden decrease in feedwater temperature following heater string isolation. Decreasing feedwater temperature will cause reactor power to increase and the power distribution to peak in the bottom of the core.

The motor driven feedwater pumps take the preheated water and further increases the pressure to a value above reactor pressure. The amount of feedwater flowing to the reactor vessel is controlled by varying the position of the feedwater regulating valves.

The discharge of the feedwater regulating valves is directed to the high pressure feedwater heater strings for the final stage of feedwater heating. Two feedwater lines penetrate the primary containment and further divide into a total of four lines. Each of the four supply lines provide feedwater to its respective sparger. The feedwater spargers distribute the flow of feedwater within the vessel annulus area.

NEW Condensate & Feedwater System

Figure 6.7-2 ===>>>

New Condensate and Feedwater System

The condensate and feedwater system, shown in Figure 6.7-2, is an integral part of the plant's conventional regenerative steam cycle. The steam exhausted from the three low pressure turbines is condensed in the main condenser and collected in the condenser hotwell along with various equipment drains. The condensate is removed from the hotwell by three condensate pumps. The condensate pumps provide the driving force for the condensate which flows through the (SJAE) condensers, steam packing exhauster condenser, and offgas condensers to perform a heat removal function. At this point the condensate is directed to the condensate demineralizers and through the process of ion exchange, impurities are removed. After the demineralizers, booster pumps increase the driving force of the condensate flowing through strings of low pressure feedwater heaters. The turbine driven, variable speed, feedwater pumps take the condensate and increase the pressure to a value above reactor pressure.

The amount of feedwater flowing to the reactor vessel is controlled by varying the speed of the turbine driven reactor feed pumps. The discharge of the feedwater pumps is directed to the high pressure feedwater heater strings for the final stage of feedwater heating. Two feedwater lines penetrate the primary containment and then further divide into a total of six lines which penetrate the reactor vessel. Each line supplies feedwater to its respective feedwater sparger. The feedwater spargers distribute the flow of feedwater within the vessel annulus area.

Feedwater Control System

Feedwater Control System

The feedwater control system regulates the flow of feedwater to the reactor vessel in order to maintain reactor water level within the normal range during all modes of plant operation. The regulation of feedwater flow is accomplished by modulating the position of feedwater regulating valves or feed pump turbine speed. The feedwater control system measures and uses total steam flow, total feedwater flow, and reactor vessel water level signals to carry out its function.

Discussion of the two basic types of feedwater control systems are given in the paragraphs that follow.

Regulation of Feed Flow with Feedwater Regulating Valves

Figure 6.7-3 ====>>>>

Regulation of Feed Flow with Feedwater Regulating Valves

The feedwater control system (Figure 6.7-3) used to regulate the flow of feedwater via feedwater regulating valves has four modes of operation, each with a specific purpose.

Manual Operation

Used for feedwater control at low powers or for a water level problem.

Single-Element Operation

Used to control the low flow feedwater regulating valve and the normal feedwater regulating valves.

Three-Element Operation

Used to control the feedwater regulating valves.

Objective #2

Runout Flow Control

Allows the maximum feedwater flow possible without overloading or tripping the motor driven reactor feedwater pumps.

During normal operation the feedwater control system regulates reactor vessel water level by measuring different parameters:

- mass flow rate leaving the reactor vessel (steam),
- mass flow rate returning to the vessel (feedwater), and
- the mass inventory of water in the reactor vessel (level).

The three parameters are combined to develop a signal that is used to modulate the opening of the feedwater regulating valves.

During startups, shutdowns, and low power operation the rate of feedwater flow to the vessel is controlled by the low flow feedwater regulating valve.

Component Description

The components of this system are discussed in the paragraphs that follow.

Reactor Water Level Instrumentation

Reactor water level is measured by two independent level transmitters with a range of 0 to 60 inches. Only one of the two instruments may provide level signals to the FWCS at a time. Selecting either level A or level B instrument is accomplished via a level selector switch.

Total Steam Flow

Steam flow is calculated in each of the four steam lines by measuring the differential pressure across a flow restrictor. The calculated steam flow signals are sent to a four input summer which develops a total steam flow signal. The total steam flow signal is used as an input to the steam flow/feed flow summer, rod worth minimizer system and steam leak detection system.

Total Feedwater Flow

Feedwater flow is measured by venturi flow elements located in the two feedwater lines penetrating the drywell. The output signals from the flow transmitters are sent to a feedwater flow summer that generates a total feedwater flow signal. The total feedwater flow signal is used as an input to the steam flow/feed flow summer, rod worth minimizer system, flow integrator, RFC System, and the runout flow controller.

Steam Flow/Feed Flow Summer

The feedwater flow summer output (- signal) and steam flow summer output (+ signal) are sent to the steam flow/feed flow summer where they are summed to produce a base signal for the FWCS. If steam flow and feed flow are not equal, this summer will produce a signal either greater than or less than the base signal. The algebraic signs are such that when steam flow exceeds feedwater flow, the output signal will modify the level signal to indicate the need for additional feedwater flow. Thus, an anticipatory signal is developed which will correct for projected changes in level due to process flow changes. This anticipatory signal corrects feedwater flow to lessen the effect of changes on reactor level due to a change in steam demand.

Level/Flow Summer

The output of the steam flow/feed flow summer, a flow error signal, is compared with the selected reactor water level signal to produce an output signal referred to as the modified level signal. The flow error signal provides anticipation of the change in the reactor vessel water level that will result from a change in load. The level signal provides a reference for any mismatch between the steam flow and feed flow that causes the level to rise or fall.

Master Level Controller

The master level controller is provided to control either or both feedwater regulating valves to achieve the desired feedwater flow. Both single element and three element control modes of operation are available as determined by the mode selector switch.

Feedwater Regulating Valve Control

The feedwater regulating valves are positioned by valve operators. Air is supplied by a valve positioner to both the top and bottom on the valve operator diaphragm. Increasing the air pressure to the top and decreasing the air pressure on the bottom of the diaphragm causes the valve to close. The positioner output is controlled by a 3-15 psig air signal from the E/P converter. The E/P converter output is controlled, in turn, by an electrical signal from the FWCS controllers.

Objective # 2

Runout Operation

The runout flow control network is provided to prevent tripping a reactor feed pump on overcurrent or low suction pressure due to an abnormally high flow. The flow through each of the three RFPs is monitored by devices called alarm units. If one or more RFPs exceed the alarm unit setpoint (5.6×10^6 lbm/hr), a RFP runout relay is energized. The runout relays control the AA solenoid and is energized only when two RFPs are running. The BB solenoid is energized if a runout condition is sensed by the runout relay.

Energizing the BB solenoid removes the M/A transfer station(s) from control and places the runout flow controller in the control circuit. The runout relay also causes the feedwater regulating valve bypass valve to close.

The runout flow controller compares a fixed setpoint with the total feedwater flow. If the total feedwater flow is greater than the fixed setpoint, a negative error signal is generated. The integrator output decreases and the feed regulating valves close until the feedwater flow matches the maximum setpoint allowed. The runout relay resets automatically when level indication increases to 20 inches. Manual reset of the runout relay is allowed if level is below 20 inches provided that the runout condition is not present.

Objective # 3

Figure 6.7-4

Scram Response Operation

Feedwater systems with feedwater regulating valves or slow responding turbine driven feedwater pumps tend to over fill the reactor vessel following a scram. To counteract this effect, the FWCS reduces the level demand signal by 50% following a scram. The master controller output is returned to its normal demanded value upon resetting the reactor scram.

Regulation of RFPTs

The FWCS controls reactor water level low enough to minimize carryover, a condition that entrains moisture in the steam leaving the reactor vessel. Conversely, the FWCS controls water level high enough to minimize carryunder, a condition in which steam is entrained in the reactor vessel annulus water.

Reactor water level is measured by three independent sensing networks, each consisting of a differential pressure transmitter connected to a water reference condensing chamber leg located in the drywell. Feedwater mass flow rate is measured by flow transmitters coupled across flow elements in the feedwater lines. Total feedwater flow rate, as used by this system, is the sum of the signals from the feedwater lines. Steam mass flow rate through each of the steam lines is measured by differential pressure transmitters connected across the steam flow elbow tap in each steam line. The steam flow signals are summed before being used by the feedwater control circuit.

The FWCS, Figure 6.7-4, generates a signal that is used to regulate the position of the turbine speed control steam supply valves, thereby controlling the pumping effort of the turbine driven reactor feed pumps. The FWCS also generates the control signal that is used to position the reactor fill valve and the discharge throttle valve bypass (DTVB) during low power operation.

Summary

Condensate and feedwater systems are designed by the architectural engineer in concurrence with the utility; very few are the same. However, all systems must have a means of delivering the water at sufficient pressure and volume to maintain reactor vessel water level during normal system operation. In addition, the condensate and feedwater system will cleanup and preheat the water prior to delivering it to the reactor vessel.

The feedwater control systems consists of two basic types with small variations to account for the specific condensate and feedwater system being controlled.

Learning Objectives View Graph

7.2 Oyster Creek Log Summary

Learning Objectives :

1. Explain why this event is only a problem for BWR/2 product lines.
2. List the two areas of the reactor vessel that are monitored to determine vessel water level.

Introduction

7.2.1 Introduction

Oyster Creek is a BWR/2 plant rated at 1930 MWt and 670 MWe. At the time of the incident, May 2, 1979, the unit was operating at 98 percent power. At approximately 1350 hours an inadvertent reactor high pressure scram occurred during surveillance testing on the isolation condenser high pressure initiation switches.

The technician performing the test was in the process of verifying that the sensing line excess flow check valve was open when the scram occurred. The scram was attributed to a momentary simultaneous operation of pressure switches due to a hydraulic disturbance associated with valve manipulations required by procedure to verify the position of the excess flow check valve. The hydraulic disturbance also caused a momentary trip of the isolation condenser initiation switches. Two of the four reactor high pressure scram sensors share a common sensing line with the isolation condenser initiation switches being tested. These sensors were not closed long enough to initiate an automatic initiation of the isolation condensers since a time delay is involved in the initiation logic. However, these sensors are also used in the automatic recirculation pump trip logic which did operate (no time delay involved).

Figure 7.2-1

One of two startup transformers, SB, was out of service to perform an inspection of its associated 4160 volt cabling (permitted by Technical Specifications). Transformer SB supplies off site power to one half of the station electrical distribution system (Figure 7.2-1) when power is not available through the station auxiliary transformer. The 4160 volt busses which receive power from SB are 1B and 1D. Buss 1D supplies power to certain redundant safety systems and is designed to be powered from the number 2 diesel generator in the event power is not available from either the auxiliary or startup transformer. Buss 1B supplies 4160 volt power to non-safety related systems and hence, does not have a diesel backup power source.

One of the five recirculation loops, loop D, was not in service due to a faulty seal cooler cooling coil. The pump suction valve was open, discharge valve closed, and discharge valve bypass open. No other systems and/or components important to the event were out of service.

Event Description

Figure 7.2-2

Event Description

A reactor scram occurred for the reasons described above, coupled with a simultaneous trip of the four operating recirculation pumps. The control room operator verified that all control rods inserted and proceeded to drive in the IRMs and SRMs. At this time, 4160 volt power was being supplied from the main turbine generator via the auxiliary transformer. Steam flow started decreasing due to loss of heat production. Feed flow remained at full flow rate.

The turbine generator subsequently tripped on reverse power as designed which initiated an automatic transfer of power to the startup transformers. Power to busses 1A and 1C successfully transferred from the auxiliary transformer to startup transformer SA. Since SB was out of service at this time, power was lost to busses 1B and 1D which caused an automatic start of the number 2 diesel generator.

Loss of power to bus 1B resulted in loss of condensate pumps and feedwater pumps B and C. Although power was available to the A condensate and feedwater pumps, the A feedwater pump tripped on low suction pressure. With mass inventory leaving the reactor vessel through the steam bypass valves with no make-up, reactor water level decreased.

In anticipation of low-low water level (level 2), automatic isolation of the reactor, the operator closed the MSIVs. To establish a heat sink to remove decay heat from the reactor, the B isolation condenser was placed into service (Figure 7.2-2). The operator closed the A and E recirculation loop discharge valves (stroke time is approximately 2 minutes). It was postulated that the remaining two loops were also closed by the operator. The conclusion that the five recirculation pump discharge valves were closed was based upon subsequent loop temperature changes observed later in the event.

The temperature of the E recirculation loop decreased due to the addition of cold water from the isolation condenser condensate return line. Loops A, B, and C temperatures increased slightly which was attributed to natural circulation forcing hot water (536°F) through the loops that were previously cooled by the addition of cold feedwater.

Water inventory shifted from the core area to the downcomer region due to the isolation condenser returning condensed steam from the core area to the downcomer. The water inventory shift continued as the discharge valves moved in the closed direction.

The cooldown of E recirculation loop stopped when the discharge valves reached their fully closed positions. Indicated reactor water level continued to increase due to the shift in water inventory. Reactor pressure continued to decrease as a result of isolation condenser operation. To reduce the rate of cooldown the B isolation condenser was removed from service. As a result, indicated water level decreased due to water returning to the core region from the downcomer region via the five 2 inch recirculation loop discharge valves bypass lines. The recirculation loops discharge temperatures reached equilibrium and then began a slow cooldown trend.

The operator placed both isolation condensers in service to gain control of the heatup. This caused an increase in indicated water level and a decrease in pressure. To slow the rate of cooldown, the B isolation condenser was removed from service. At that moment, indicated water level reached a maximum of approximately 14.4 feet above the top of active fuel. Shortly after B isolation condenser was removed from service, indicated water level decreased to 13 feet 8 inches above active fuel, and stabilized. Water level remained stable during that period because the head of water in the downcomer region was sufficient to establish equilibrium between the water entering the core region via the five 2 inch bypass lines and the condensed steam returning to the downcomer from the isolation condenser.

During performance of local alarm verification and indicator checks the low-low-low (level 1) water level indicators were found to be below their alarm setpoint (10 inches). A recheck performed locally showed that the pointers were active (moving) although they continued to read below their alarm point. Also the instruments were indicating at or slightly above their lower level of detection.

The A isolation condenser was removed from service, thus stopping the removal of inventory from the core region. Indicated water level decreased as the water in the downcomer region flowed into the core region.

The C recirculation pump was started to provide a better indication of the plant cooldown rate. After the pump started, indicated water level dropped approximately 3 feet in less than two minutes causing the operator to stop the pump and investigate the reason for the level drop. In response to the level problem, the operator attempted to start the A feedwater pump. The pump failed to start due to a tripped overload on the auxiliary oil pump which provides an interlock in the feedwater pump starting sequence. The auxiliary oil pump was started locally followed by starting the A Feedwater pump. Indicated water level increased to a level corresponding to 13 feet 8 inches above the top of the core. The operator now recognized that all five recirculation loop discharge valves were closed and indicated water level and actual water level may not have been the same.

The A recirculation pump was placed in service which removed the disparity between the water level instruments. Indicated water level dropped approximately three feet to 11 feet 4 inches above the top of the fuel. Recirculation loop A temperature increased from 375°F to 465°F after starting the pump. In addition, the low-low-low water level condition cleared at this time.

Areas of Concern

Objective #1

The need for better communication between the downcomer region and the core region was apparent. Therefore, a Technical Specification revision was issued which required that at least two recirculation loops will be lined up with their respective suction and discharge valves open during all modes of plant operation. The requirement was so important that it was placed in the Safety Limit section of Technical Specification.

Corrective Actions

A confirmatory order, dated March 14, 1983, was issued that required an interlock system for the recirculation pump loops. In lieu of the interlock, Oyster Creek received approval for the installation of an alarm system that would provide annunciation when the fourth loop was isolated. This modification was required to be completed by October 1986.

Related subsequent Safety Limit Violation

While performing maintenance on the Reactor Building Closed Cooling Water System (RBCCW) on September 11, 1987, at 2:30 a.m., an operator identified leakage within the system and proceeded to isolate one of the two recirculation loops which was in service at the time. This is a violation of Technical Specifications 2.1, Fuel Cladding Integrity, which requires two recirculation loops to have their suction and discharge valves in the full open position during all modes of operation. Within seconds the operator placed one of the three isolated loops into operation. The total elapsed time with less than two loops in service was approximately 2 and one half minutes. The plant was in shutdown and on shutdown cooling with reactor temperature about 140 °F prior to the event.

Summary

Unlike other BWRs the BWR/2 reactor vessels do not have direct communication from the annulus region to the core inlet plenum. Water must exit the reactor vessel via recirculation loops and then reenter the vessel bottom head.

Learning Objectives

Learning Objectives :

1. Explain the need for a maximum combined flow limiter in the Electro Hydraulic Control System.
2. Explain the term half isolation.
3. Explain why isolation valve control switches must be in the closed position prior to resetting the isolation signal.
4. Explain the need to reset a reactor scram when the condition has cleared.

Introduction

Introduction

Prior to reading the event sequence cover:
Fugure 7.3-1.
- scram air header operation
  - scram valves
  - SDV vent and drain valves

In the discussion, **cover the RPS power supply**. Transfer from the MG sets to the alternate power source --- break before make. **Have the class provied the loads on the RPS bus.**
- RPS system
- Radiation monitoring
- Neutron Monitoring
- Nuclear Steam Supply Shutoff System

Isolation logic, except for the MSIVs, are arranged in an inboard outboard configuration. A loss of power to one of the RPS busses deenergizes either the inboard or outboard logic causing the associated inboard or outboard valves to close.

Coverage of Events Log

Coverage of events log

Dresden Unit 3 is a BWR/3 plant rated at 2527 MWt and 809 MWe. At the time of the incident, September 19, 1985, the unit was operating at 83 percent reactor power. At approximately 1339 hours, Dresden Unit 3 tripped from an average power range monitor (APRM) high-high flux scram.

Several days before the Unit-3 scram occurred, the Instrument Maintenance Department had installed a multi-point recorder to various leads in the EHC system cabinet. Unit 3 had been experiencing problems with the Economic Generation Control (EGC) portion of the EHC system and to identify the cause of the problems the multipoint recorder was installed to monitor certain parameters.

As luck would have it the IM department failed to inform the control room and when the test connections were removed one of the circuit cards was also moved. This caused a zero maximum combined flow output voltage signal resulting in closure of all the turbine control valves and bypass valves. The closure of the control valves caused a reactor pressure spike, resulting in a high neutron flux and a subsequent APRM high-high flux scram.

During the scram recovery, difficulty was encountered in resetting reactor protection system (RPS) channel B. Also during the recovery, the scram discharge volume (SDV) vent and drain valves opened while the control rod drive scram inlet and outlet valves on every CRD hydraulic control unit were open. This resulted in the release of reactor vessel water inventory to the reactor building.

Failure of rods to fully insert

Failure of rods to fully insert

At 1339 (05) aproximatly 20 control rods indicated position 02. Rods stopping at position 02 is common.

- Stop piston seals normally restric reactor water flow into the buffer flow region, (Area above the drive piston).
- If the stop piston seals leak, reactor water will be felt in the buffer region, reducing the available driving force and impeding the upward drive movemnt.
- Per design of the drive, as the drive moves upward the buffer holes become covered, one by one, decreasing its upward velocity.
- With the added impedance to upward movement, the drive has a tendency to stop at position 02.
- If all of the control rods stopped at position 02 the reactor would still be shutdown under all conditions.

Isolations of Groups II and III

Reactor water level decreases following a reactor scram due to void collapse, caused by the decrease in reactor heat output. Level will usually decrease to about -15 inches.

- Secondary containment ventillation isolates and SGT starts
- Drywell equipment and floor drains isolate
- RHR shutdown cooling isolation signal
- Group III - RWCU isolation

Typical operator scram action

- Follow up the scram by placing the mode switch in shutdown or refuel. Depress the manual scram buttons
- Verify all rods inserted
  - mode switch in refuel to check one rod permissive light
  - full core display
  - computer print out
- ensure level and pressure are resonding as expected.

- reset group isolations and realign systems

Failure of Scram Reset

When the scram occurred, the Unit 3 reactor operator followed scram procedure DGP 2-3. When moving the reactor mode switch to the "refuel" position, it was left partially between the "shut-down" and "refuel" position. This generated a reactor mode switch scram signal on the 'B' RPS channel which could not be reset. The last time the operator attempted to reset the reactor (approximately ten minutes after the scram) he was only able to reset the 'A'RPS channel. Approximately one hour and sixteen minutes after the scram, the Unit 3 operating engineer noticed the mode switch in the midposition. When the mode switch was fully placed in the "refuel" position, the reactor operator was able to fully reset the reactor scram signal.

Scram Discharge Volume Air Header Failure

Figure 7.3-1

The scram air header is designed to supply control air to the SDV air operated vent and drain valves and all 137 CRD scram inlet and outlet valves. During a reactor scram, the air supply to the SDV header is isolated by the SDV backup scram valves. The air within the isolated portion of the header is vented to the Reactor Building atmosphere by each control rod drive hydraulic control unit scram pilot valves and the scram dump valves, Figure 7.3-1. The backup scram valves also depressurize the header through exhaust ports. The system is designed such that, even during a half scram condition, full system pressure is supplied to the header.

During the event, only partial system pressure was restored after the reactor operator reset the "A" RPS channel. While the degraded condition existed, maximum air header pressure was only 38 psig. This pressure was sufficient to automatically open the vent and drain valves, but was not sufficient to close the scram inlet and outlet valves. This provided a direct path for primary system coolant from the reactor vessel to enter the Reactor Building. The SDV vent lines are routed to the reactor water cleanup pump and shutdown cooling heat exchanger area atmosphere. The SDV drain valves are routed to the Reactor Building equipment drain sump. The SDV remained in an unisolated condition for approximately 33 minutes, resulting in the release of contaminated water and steam into the second and third floors of the Reactor Building. The shutdown cooling pump room area passed steam through a ventilation duct into the X area (Also known as the steam tunnel), where the outboard MSIVs are located. This resulted in an increase in X area temperature and a resultant isolation signal to close the MSIVs. The air header pressure returned to normal when the reactor operator reset channel 'B'. No contamination was released outside the reactor Building.

Figure 7.3-2 & 3

After the SDV system was isolated and the unit was placed in cold shutdown, several functional tests were performed on the SDV system. The cause of the air header system failure remains unknown.

Areas of Concern

Investigation of plant records revealed a similar event had occurred on Unit 2 on April 29, 1972. The unit was in cold shutdown at the time of the event and no primary containment inventory had been lost. Following the event, ~~had occurred,~~ a study was performed by the General Electric Company. Figure 7.3-2 shows the two pilot valves in series with channel 'A' RPS reset and 'B' tripped. Tests performed indicated that at low air supply pressure, approximately 5 psi air pressure would pass through the pressure diaphragm of the 'A' RPS valve and leak past exhaust diaphragms of the 'B' RPS valves.

According to the valve manufacture, Asco, a minimum of 10 psi across the valve is required to seat an exhaust diaphragm. However, actual tests showed that for the 'A' valve 6 psid was required and only 4 psid was required to close the 'B' valve when it was energized as indicated in Figure 7.3-3.

Corrective Actions

The Dresden Station Unit 2/3 scram procedure DGP 2-3 was revised as follows:

- The reactor operator was directed to place the mode switch to the shutdown position after any scram occurs. This will help prevent any future mid-positions of the mode switch. If the mode switch is replaced in the future with a more reliable type, this instruction will be removed.

- The reactor operator was directed to close the SDV vent and drain valves using the individual control switches before resetting the scram. This will prevent any possible steam releases in the future if the scram air header pressure were to become degraded.
- A caution statement was added to the procedure. If the SDV vent and drain valves will not close during any half scram condition, following a full reactor scram reset, the reactor operator is instructed to manually scram the reset channel.

- The reactor mode switch contacts were visually inspected for any impairment.

Figure 7.3-4

PRA Insight

In addition to providing power to the reactor protection system, the RPS buses provide power to the primary containment isolation control system (PCIS). This system operates valves as required to isolate the reactor vessel and/or primary containment to conserve coolant inventory and prevent the release of radioactive materials. Loss of power to RPS bus 'B' de-energizes all 'B' train logic in the isolation control system and results in the isolation of among other things the Reactor Water Cleanup System and the shutdown cooling mode of the Residual Heat Removal (RHR) System.

On February 3, 1990 an event occurred at Susquehanna Unit 1 that conveys the important interrelationship between the RPS and the PCIS. Unit 1 was shutdown on February 1, 1990 for maintenance. Two days later a test of the alternate power supply to RPS bus 'B' was conducted. When normal power was secured, the alternate supply failed to close in on the bus. The loss of power resulted in isolation of certain valves controlled by this system including a RHR shutdown cooling suction supply valve. With normal shutdown cooling lost, the reactor water temperature began to increase. Operators stopped the coolant temperature rise at 252°F by opening three Safety Relief Valves (SRVs). Makeup water was provided by the control rod drive pump.

An event tree model of sequences to core damage was developed considering the potential unavailability of mitigating features described in Susquehanna's procedures. This event tree (Figure 7.3-4), addresses RPV makeup via the control rod drive, condensate, core spray, or low pressure coolant injection systems. If the SRVs are used, then suppression pool cooling is also assumed required.

Figure 7.3-4 includes the following core damage sequences:

- Successful use of the SRVs and SP cooling for heat removal, but failure to provide RPV makeup via the CRD, condensate, core spray and LPCI sys-tems.
- Failure of SP cooling following successful opening of the SRVs.RWCU is successful but makeup via the conden-sate system fails.
- Failure of SP cooling following successful opening of the SRVs. RWCU fails to provide letdown/heat removal.
- Similar to sequence 2 except the SRVs fail to open.
- Similar to sequence 3 except the SRVs fail to open.

The conditional probability of subsequent core damage associated with the event (LER 387/PNO-I-90-8) is conservatively estimated to be 4.1×10^{-5}. The relative significance of this event compared to the postulated events at Susquehanna is indicated below:

Summary

In the Dresden event the out put of the Maximum Combined Flow (MCF) limiter of the EHC logic failed to zero. Thus, closing all turbine valves and BPVs. The purpose of the MCF is ~~to limiter~~ is to limit the maximum amount of steam the turbine and BPVs can open and remove steam from the vessel if the pressure regulator should fail. In addition, the RPS was not capable of being fully reset. Should a leak occur in the scram discharge volume during a scram condition there are no current means available to detect this leak other than visual. Therefore, if a reactor scram occurs it is very important for the RPS to be reset if the scram signal is cleared.

The RPS provides power to other systems in addition to the RPS logic. One of those systems in the Nuclear Steam Supply Shutoff System (NSSSS). The NSSSS is divided into two division, division 1 and division 2. Each division controls power to either an inboard or an outboard isolation valve logic. If the divisional logic is deenergized, the valve (s) will close. If only one RPS buss looses power then either the inboard or out board isolation valve for a particular system will close providing what is termed a half isolation.

UNITED STATES NUCLEAR REGULATORY COMMISSION TECHNICAL TRAINING CENTER

GE TECHNOLOGY ADVANCED MANUAL (R-504B)

This manual has been developed as a text and reference document for the General Electric Advanced Course. It should be used as a supplementary study guide during the student's attendance at this course.

The manual contains a considerable amount of detailed design and operational information. It may contain information that could be considered "proprietary" by certain companies that design and supply components and systems for nuclear facilities. This manual was developed strictly for the use of NRC personnel, for training and subsequent reference purposes, and should not be distributed outside the NRC.

This manual was compiled by members of the Technical Training Center, GE Technology Staff.

List of Effective Revisions

Chapter	Revision
1.0	1195
2.0	
2.1	0397
2.2	0301
3.0	0601
3.1	0401
3.2	0298
3.3	0498
3.4	0601
3.5	0898
4.0	
4.1	0397
4.2	0195
4.3	0400
4.4	0397
4.5	0501
4.6	1195
4.7	0397
4.8	0500
4.9	0400
4.10	0196
4.11	0196
4.12	0601
5.0	
5.1	0497
6.0	1195
6.1	1195
6.2	0497
6.3	0497
6.4	0497
6.5	0497
6.6	0497
6.7	1295
6.8	0195
6.9	0195

7.0	
7.1	0497
7.2	0497
7.3	0797

Day	Title	Chapter
1	Course Introduction	
	Technical Specification Overview	3.0
	Classroom Exercise - EHC Problems	2.1
	Technical Issue - Station Blackout	4.5
	Technical Issue - IGSCC	4.9
2	Classroom Exercise - Core Heat Balance	2.2
	Technical Specifications - Stuck Control Rod	3.1
	Transient Session - Introduction	5.1
3	Technical Specifications - Thermal Limits	3.2
	Technical Issues - Shutdown Plant Problems	4.10
	Transient Session	5.1
4	BWR Differences - Reactor Isolation and Inventory Control	6.3
	Technical Issue - Power Oscillation	4.3
	Transient Session	5.1
5	BWR Differences - Emergency Core Cooling Systems	6.4
	Technical Specifications - Control Room Log 1	3.3
	Transient Session	5.1
6	Technical Specifications - Control Room Log 2	3.4
	Transient Session	5.1
	Plant Event - Oyster Creek Level Problem	7.2
7	BWR Differences - Containment	6.5
	Technical Specifications - Control Room Log 3	3.5
	Technical Issue - Air Systems Problems	4.6
	Transient Session	5.1
8	Technical Issue - Service Water Systems Problems	4.8
	Technical Issue - Emergency Action Levels	4.12
	Transient Session	5.1
9	Technical Issue - Interfacing System LOCA	4.7
	Plant Event - Dresden Log Summary	7.3
	Technical Issue - ATWS	4.2
	Review	
10	**Course Exam**	

GE Advanced Technology Course (BWR/4, R-504B)

Course Objectives

The GE advanced technology course is designed to provide the student with practical exercises to reinforce system responses to normal, abnormal, and emergency transients. This will be accomplished by providing lectures,case studies, transient responses, and technical specification examples with emphasis in the following areas:

- Technical issues
- Analysis of integrated plant response to normal operating and transient conditions
- Facility abnormal events
- Technical specifications utilization
- Probability risk assessment insights
- Major differences in Boiling Water Reactors
  - reactor vessel construction
  - recirculation and recirculation flow control
  - reactor isolation and inventory control
  - emergency core cooling systems
  - rod control systems
  - containments

Students will be required to prepare for the lectures by reading the appropriate course material, participate in practical exercises, and respond to questions during lectures.

Students will demonstrate the ability to analyze conditional points on a transient curve, respond correctly to multiple choice and subjective questions, and list progressive paths in technical specifications for plant operation following equipment and/or system malfunction by the successful completion of a comprehensive final examination. Successful completion of a comprehensive final examination, with a test score of 70%, is required in the following areas.

• Transients	25pts.
• Technical Issues	15pts.
• Technical Specifications	10pts.

STUDENT INFORMATION SHEET

PLEASE PRINT THE FOLLOWING INFORMATION:

Course Title: ____________________

Course Dates: ____________________

Name: ____________________
(How you want it to appear on Training Certificate

Social Security No: ___/___/___ Job Title: ____________________

Phone No: __________ Mailing Address: ____________________

____
(No P.O. Boxes please)

Motel where you are staying: ____________________ Room No: __________

Name and number of person to call in an emergency: ____________________

____

Estimated Travel Cost (including transportation costs): ____________________

Name of Immediate Supervisor: ____________________

Name of Division Director: ____________________ **Name of Division:** __________

Please provide the following background information: (Please circle one)

1. Highest Level of Education:

   Doctorate Masters Bachelors Associate Other

2. Subject Matter Specialty:

   Engineering Physical Science Math or Statistics Other Science Other

3. Years of Nuclear Experience: >9 7-9 4-6 1-3 <1

4. Type of Nuclear Experience:

   Commercial BWR Commercial PWR RO/SRO Navy Test Reactor Other

5. Years with NRC: >9 7-9 4-6 1-3 <1

6. Previous TTC sponsored training attended: ____________________

____

____

STUDENT HANDOUT SHEET

TTC PHONE SYSTEM

1. Commercial: 423-855-6500
2. Incoming calls for students — see paragraph on STUDENT MESSAGES
3. Classroom phones are connected on a common internal line and can only be used to call other areas inside the Training Center.
4. Wall phones in the 2nd floor student lounge area can be used for making outside calls.
5. To make local calls: dial 9 + local number
6. To make long distance calls: dial 9 + 1 + Area Code + Number

Note: *TTC is now on detailed billing for actual telephone usage and all calls are listed on a computer printout. Please limit calls home to no more than 5 minutes, per NRC Manual Chapter Appendix 1501, Part IV.D.5.*

AREA INFORMATION

1. Restaurants — Eastgate Mall, Brainerd Road area
2. Hospital — Humana in East Ridge — Phone: 894-7870
3. Emergency Phone Number — 911

COURSE RELATED ITEMS

1. Working hours are from 7:30 a.m. to 4:15 p.m. Classroom presentations are from 8:00 a.m. to 4:00 p.m. Lunch break will begin between 11:30 a.m. – 12:00 p.m. at the discretion of the instructor.
2. The Course Director and Course Instructor(s) are available to answer questions before and after class, during the breaks, and during lunch time with prior arrangement. Instructors not in the classroom can be reached via telephone. Please call ahead to ensure availability.
3. All course related materials (pencil, paper, manuals, notebooks, and markers) are provided. If there is a need for additional material or administrative service, please coordinate with the Course Instructors.
4. Shipping boxes will be provided for the mailing of course materials (manuals & notebooks). Each student must write their name and address to which the box is to be mailed on a mailing label and tape it to the outside of their box. The TTC staff will affix the proper postage.
5. Student registration for all TTC courses is accomplished through Training Coordinators. The TTC staff does not register students directly.

TTC SECURITY

NRC badges are required to be worn while at the TTC. Please promptly notify Course Director if your badge is lost or misplaced.

STUDENT MESSAGES

There is a printer located in the 2nd floor student computer room. All non-emergency student messages will be sent to this printer. It is your responsibility to check this printer for messages. If there are messages on the printer, please post them on the bulletin board above the printer.

COMPUTERS FOR STUDENT USE

There are several standard NRC NT Workstations located in the 2nd floor student computer room. These computers are equipped with the NRC suite of programs, including internet access. Instructions are posted for accessing individual e-mail accounts.

FIRST AID KITS

First Aid Kits are located in the instructor's desk of each simulator, in the second floor student lounge in the sink cabinet, and the sink cabinet in the staff lounge on the second floor. In addition, each location also has a "Body Fluid Barrier Kit". These kits are to be used in the event of personnel injury involving serious bleeding. Each kit contains two complete packets each with: 1 pair of latex gloves, 1 face shield, 1 mouth-to-mouth barrier, 1 protective garment, 2 antiseptic towelettes, and 1 biohazard disposable bag.

TAX EXEMPTION CERTIFICATES

NOTE: We do not have Tax Exempt Certificates for lodging in Chattanooga. Chattanooga is not one of the localities permitted to use these certificates. For a list of locations which are allowed to use them, see the Federal Travel Directory published monthly by GSA.

Please remember that you, as students, represent the NRC and when you knowingly avoid paying Tennessee State Tax, the results can have a negative effect on the Agency.

If you are not able to obtain adequate lodging and stay within the per diem rate established by GSA, advise your Management Support or DRMA office so the proper authorities can be notified.

FAX and COPYING AVAILABILITY

There are copy machines located on the 2nd, 3rd, and 4th floors. Students are asked to use the copiers on the 3rd and 4th floors for smaller jobs. If there is a need to copy larger jobs please coordinate with the Course Instructors for use of the large volume copy machine on the second floor.

Students needing to send a FAX can do so on the FAX machine located in the 2nd floor student computer room.

Students needing to receive a FAX during class time can have it sent to 423-855-6543. The FAX can then be picked up on the second floor in the Admin area.

TTC 500 LEVEL COURSE EVALUATION

Course Title/Name: ____________________

Location: ____________________ **Course Dates:** ____________

Instructions

In order to maintain and improve the quality and applicability of TTC courses it is necessary to obtain feedback from attending students. Please rate the following subject areas. Amplifying comments are desired but not required. Please place your amplifying comments in the section for written comments. Please print your name at the bottom of this form to allow for follow-up and amplification of significant issues or suggestions.

		Strongly Disagree	Disagree	Agree	Strongly Agree
1.	Stated course objectives were met				
2.	Class exercises and demonstrations were effective in reinforcing covered concepts and introducing new concepts.				
3.	Learning objectives were helpful in identifying important lecture concepts.				
4.	Classroom presentations adequately covered the learning objectives				
5.	The course manual adequately covered course topics where applicable.				
6.	The course manual will be useful as a future reference.				
7.	Visual aids reinforced the presentation of course materials.				
8.	Completion of this course will assist me in my regulatory activities.				

	Unsatisfactory	Marginal	Satisfactory	Good	Excellent
9. Overall Course Rating					

Name: ____________________

(Note: Additional questions on back of form)

10. What did you like best or find most helpful about the course?

11. What did you like least about the course?

12. What subjects might be added or expanded?

13. What subjects might be deleted or discussed in less detail?

14. How will this course aid you in your ability to do your job as a regulator?

15. What could be done to make this course more useful in aiding you in your ability to do carry out your regulatory activities?

16. Additional comments:

QUICK REFERENCE METRIC CONVERSION TABLES

MECHANICS

QUANTITY	FROM INCH - POUND UNITS	TO METRIC UNITS	MULTIPLY BY
mass (weight)	ton (short)	t (metric ton)	*0.907 184 74
	lb (avdp)	kg	*0.453 592 37
moment of mass	lb · ft	kg · m	0.138 255
density	ton (short)/yd^3	t/m^3	1.186 553
	lb/ft^3	kg/m^3	16.018 46
concentration (mass)	lb/gal	g/L	119.826 4
momentum	lb · ft/s	kg · m/s	0.138 255
angular momentum	lb · ft^2/s	kg · m^2/s	0.042 140 11
moment of inertia	lb · ft^2	kg · m^2	0.042 140 11
force	kip (kilopound)	kN (kilonewton)	4.448 222
	lbf	N (newton)	4.448 222
moment of force, torque	lbf · ft	N · m	1.355 818
	lbf · in	N · m	0.112 984 8
pressure	atm (std)	kPa (kilopascal)	*101.325
	bar	kPa	*100.0
	lbf/in^2 (formerly psi)	kPa	6.894 757
	inHg (32 °F)	kPa	3.386 38
	ftH$_2$O (39.2°F)	kPa	2.988 98
	inH$_2$O (60 °F)	kPa	0.248 84
	mmHg (0 °C)	kPa	0.133 322

MECHANICS (continued)

QUANTITY	FROM INCH - POUND UNITS	TO METRIC UNITS	MULTIPLY BY
stress	kip/in^2 (formerly ksi)	MPa	6.894 757
	lbf/in^2 (formerly psi)	MPa	0.006 894 757
	lbf/in^2 (formerly psi)	kPa	6.894 757
	lbf/ft^2	kPa	0.047 880 26
energy, work	kwh	MJ	*3.6
	cal$_{th}$	J (joule)	*4.184
	Btu	kJ	1.055 056
	ft · lbf	J	1.355 818
	therm (US)	MJ	105.480 4
power	Btu/s	kW	1.055 056
	hp (electric)	kW	*0.746
	Btu/h	W	0.293 071 1

Exact conversion factors are indicated by an asterisk (*)

TO CONVERT FROM METRIC UNITS TO INCH POUND UNITS DIVIDE THE METRIC UNIT BY THE CONVERSION FACTOR.

NOTE: The information contained in this table is intended to familiarize NRC personnel with commonly used SI units and as a quick reference to aid in the understanding of documents containing SI units. The conversion factors provided have not been approved as NRC guidelines for development of licensing actions, regulations or policy.

REFERENCES: 1. Federal Standard 376A (May 5, 1983) PREFERRED METRIC UNITS FOR GENERAL USE BY THE FEDERAL GOVERNMENT
2. International Commission of Radiation Units and Measurements, ICRU Report 33 (1980), RADIATION QUANTITIES AND UNITS

QUICK REFERENCE METRIC CONVERSION TABLES

SPACE and TIME

QUANTITY	FROM INCH - POUND UNITS	TO METRIC UNITS	MULTIPLY BY
length	mi (statute)	km	1.609 347
	yd	m	* 0.914 4
	ft (int)	m	* 0.304 8
	in	cm	* 2.54
area	mi^2	km^2	2.589 998
	acre	m^2	4 046.873
	yd^2	m^2	0.836 127 4
	ft^2	m^2	* 0.092 903 04
	in^2	cm^2	* 6.451 6
volume	acre foot	m^3	1 233.489
	yd^3	m^3	0.764 554 9
	ft^3	m^3	0.028 316 85
	ft^3	L	28.316 85
	gallon	L	3.785 412
	fl oz	mL	29.573 53
	in^3	cm^3	16.387 06
velocity	mi/h	km/h	1.609 347
	ft/s	m/s	* 0.304 8
acceleration	ft/s^2	m/s^2	* 0.304 8

HEAT

QUANTITY	FROM INCH - POUND UNITS	TO METRIC UNITS	MULTIPLY BY
thermodynamic temperature	^oF	^oK	* $^oK=(^oF+459.67)/1.8$
Celsius temperature	^oF	^oC	* $^oC=(^oF-32)/1.8$
linear expansion coefficient	$^oF^{-1}$	$^oK^{-1}$ or $^oC^{-1}$	* 1.8
thermal conductivity	$(Btu \cdot in)/(ft^2 \cdot h \cdot {}^oF)$	$W/(m \cdot {}^oC)$	0.144 227 9
coefficient of heat transfer	$Btu/(ft^2 \cdot h \cdot {}^oF)$	$W/(m^2 \cdot {}^oC)$	5.678 263
heat capacity	$Btu/^oF$	$kJ/^oC$	1.899 108
specific heat capacity	$Btu/(lb \cdot {}^oF)$	$kJ/(kg \cdot {}^oC)$	* 4.186 8
entropy	$Btu/^oF$	$kJ/^oC$	1.899 108
specific entropy	$Btu/(lb \cdot {}^oF)$	$kJ/(kg \cdot {}^oC)$	* 4.186 8
specific internal energy	Btu/lb	kJ/kg	* 2.326

NUCLEAR REACTION and IONIZING RADIATION

QUANTITY	FROM INCH - POUND UNITS	TO METRIC UNITS	MULTIPLY BY
activity (of a radionuclide)	curie (Ci)	MBq	* 37,000.0
	dpm	Bq - (becquerel)	0.016 667
absorbed dose	rad	Gy (gray)	* 0.01
	rad	cGy	* 1.0
dose equivalent	rem	Sv (sievert)	* 0.01
	rem	mSv	* 10.0
	mrem	mSv	* 0.01
	mrem	μSv	* 10.0
exposure (x and gamma rays)	roentgen (R)	C/kg (coulomb)	0.000 258

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Boiling Water Reactor
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Chapter 1.0

Introduction

1.1 OPERATIONAL SUMMARY (Plant Startup)

Learning Objective :

1. Arrange the following events for a plant startup to rated power in the correct sequence:

   a. prestartup check sheet
   b. authorization for startup
   c. withdrawal of SRMs
   d. realignment of head vent
   e. withdrawal of IRMs
   f. reset HPCI and RCIC isolation
   g. SJAE's steam supply shifted to main steam
   h. mode switch transferred to run position
   i. RWM automatically bypassed
   j. synchronize generator to grid
   k. RBM placed in service
   l. oxygen concentration less than 4%

1.1.1 Introduction

Before cold startup, prestartup check lists are completed on all systems required to support startup and power operation. Included in these checks are the following: operational checks on safety related systems to ensure their availability; nuclear steam supply and balance of plant system valve and switch lineups from control room panels; and functional checks of systems such as the Neutron Monitoring Systems (NMS) and Reactor Manual Control System (RMCS). The shutdown cooling mode of the Residual Heat Removal (RHR) System is secured and the recirculation pumps are started and powered by the low frequency motor generator sets. The Recirculation Flow Control (RFC) System is in individual loop manual control. The Condensate and Feedwater System is prepared to supply water to the reactor vessel. This includes bringing chemistry into specification by recirculating water from the condenser hotwell through the condensate demineralizers and feedwater heaters. A vacuum is drawn in the main condenser to aid in the removal of noncondensible gases from the reactor vessel and main steam lines.

1.1.2 Approach to Critical and Pressurization of the Reactor

Following the completion of the prestartup checks, authorization for startup must be received from the station management. The reactor mode switch is placed in the "STARTUP" position and control rods are withdrawn, using the Rod Manual Control System, according to the specified sequence. When a control rod has been withdrawn to the full out position, a coupling check is made by attempting to further withdraw the rod. If the control rod blade is uncoupled from the control rod drive, a rod overtravel alarm is received and corrective measures must be taken. Control rod withdrawal continues until criticality is achieved. The time, rod position, reactor period, and reactor water temperature are then recorded. After neutron flux measurement overlap with the Intermediate Range Monitor System detectors has been demonstrated, the Source Range Monitor (SRM) System detectors are withdrawn as required to maintain the count rate between 10^2 and 10^5 counts per second (cps).

After the reactor is critical, a reactor period of 75 to 100 seconds is established to raise power to the heating range. The IRMs are ranged upward as required to maintain proper on scale readings. Reactor power increase continues until heating power is reached, upper range 6 to lower range 7 of IRMs. At this point, control rod withdrawal is governed procedurally at the heatup rate limit of approximately 90^0F/hr. The Technical Specification limit is 100^0F/hr.

As reactor water temperature increases, the coolant expands which causes reactor vessel level to increase. The Reactor Water Cleanup System is aligned to reject water to the main condenser or to the Liquid Radwaste System to maintain normal reactor vessel water level. It is usually more desirable to reject the excess water to the condenser in order to minimize the water processing load on the Liquid Radwaste System. This evolution continues until rated temperature and pressure are reached.

As temperature increases from 200^0F to 212^0F, the reactor vessel head vent alignment to the equipment drain sump is secured and realigned to the main steam line.

Between 5 and 120 psig, reactor steam dome pressure, the low reactor pressure isolation of Reactor Core Isolation Cooling (RCIC) and High Pressure Coolant Injection (HPCI) systems are reset and placed in standby configuration.

Surveillance for RCIC and HPCI are performed following bypass valve (BPV) opening at approximately 140 psig. Warming of the RFPs, main turbine and the Offgas System is started.

As pressure approaches 140 psig, the Electro Hydraulic Control (EHC) System pressure regulators would start to open bypass valve number 1. Following RCIC and HPCI surveillance, the pressure setpoint is increased to maintain 50 to 75 psig above reactor pressure until pressure is at 920 psig.

Between 300 and 500 psig the Steam Jet Air Ejectors (SJAEs) are shifted from auxiliary steam supply to reactor steam. At about 350 psig, a reactor feed pump is started and placed in service.

As pressure reaches 920 psig, the bypass valves begin to open to control reactor pressure at the EHC System pressure setpoint. Control rods are withdrawn to increase power, which results in further opening of the bypass valves. When power reaches about 5%, the reactor mode switch is shifted to the "RUN" mode, and the IRMs are fully withdrawn. Control rods are withdrawn until $1^1/_2$ BPVs are open, representing sufficient steam flow to roll the main turbine and provide minimum loading following synchronization to the grid.

At about this time, the Feedwater Control System (FWCS) is placed in automatic and RWCU System reject flow is discontinued.

1.1.3 Startup and Synchronization of the Generator

A turbine acceleration rate is chosen depending upon various turbine temperatures and the turbine is rolled to synchronous speed. The generator is then synchronized to the transmission system through the generator output breakers. The operator increases load on the generator by using the load selector to open the control valves. Opening of the control valves causes the bypass valves to automatically close to regulate reactor pressure.

Once all bypass valves are closed, any further increase of the load selector results in a setpoint adjustment only so the load selector is raised to the expected power level.

1.1.4 Increase of Power to Rated

Further increase in generator load is accomplished by increasing reactor power by rod withdraw and recirculation flow changes. As reactor power and pressure rises, steam throttle pressure increases which causes the EHC System to open the control valves further, thus increasing turbine and hence generator power.

Control rods are further withdrawn to increase power to 20%. At this power the second condensate and condensate booster pumps are placed in service. Additional demineralizers are placed in service as needed. The second reactor feed pump is rolled and maintained at minimum speed until needed. Feedwater control is transferred from single element to three element control.

When power exceeds 20%, the Rod Worth Minimizer (RWM) is automatically bypassed. At 25% power, thermal limits per Technical Specifications are maintained. At 30% power, the Rod Block Monitor (RBM) is activated. When reactor power reaches 40% the RFPs are balanced.

Control rods are withdrawn to just below the 80% rod line to prevent entering the instability region. Reactor power is further increased using the recirculation system until flow is greater than 35 Mlbm/hr. Control rods are then withdrawn to establish the 100% control rod pattern. When reactor recirculation pump speed is at or greater than 45%, the Recirculation Flow Control (RFC) system is placed in Master Manual. Core flow is increased until 100% (2436 MWth) power *or* 100% flow is obtained.

Twenty four hours after reaching 15% reactor power, the Primary Containment oxygen concentration must be less than or equal to 4%.

1.1.5 Startup Sequence

1. Functional and/or precritical checks have been completed and the following systems are in operation:
   a. Recirculation System
   b. Control Rod Drive Hydraulic System
   c. Closed Cooling System
   d. Circulating Water System
   e. Service Water System

f. Condensate and condensate booster pump on long cycle
g. RWCU System
h. Main Steam Isolation Valves are open
i. Moderator temperature 100^{o}F
j. All NMS are operable
k. RMCS operable
l. Steam to the Turbine Sealing Steam System
m. Containment Systems

2. Obtain the rod withdrawal sequence from nuclear engineer and get the shift engineer's approval for startup.

3. The reactor is taken critical by control rod withdrawal. Record the following:
   a. Time
   b. Rod/Gang position and number
   c. Period
   d. Reactor water temperature

4. Establish a 75-100 second period. Avoid a period shorter than 50 seconds.
   a. If period is <35 seconds, insert control rods until the reactor is subcritical and contact the nuclear and shift engineers
   b. Reactor periods <5 seconds are report-able to NRC within 24 hours.

5. Change IRM range switches to maintain between 25-75 on the 0-125 scale.

6. Keep SRM power level between 10^2 and 10^5 by withdrawing the detectors. Do not withdraw detectors to <100 cps until all IRM's are on range 3 or above. The SRM detectors may be fully withdrawn after reaching IRM range #8 and must be fully withdrawn prior to going into the run mode.
7. Raise power level by control rod withdrawal until the desired heatup rate is reached.

8. During heatup and cooldown, the following parameters shall be recorded every 15 minutes until 3 successive readings at one point are within 5 ^{0}F:
   a. Steam dome pressure (converted to temperature)
   b. Reactor bottom head drain temperature
   c. Recirc. loop A and B temperatures

9. At a reactor temperature of 190^{0}F
   a. Shut reactor head vent to drywell.
   b. Open reactor head vent to main steam line.

10. Reject water as required from the RWCU System to the main condenser to maintain a normal reactor water level.

11. At > 100 psig, start warming steam lines to RFPs and SJAEs. Reset RCIC and HPCI low pressure isolation and start warming its steam line.

12. At 150 psig, the Electro Hydraulic Control System (EHC) will start to open BPV #1.

    Avoid bypassing steam by raising the pressure set point to 920 psig. At rated steam flow, this will result in a turbine throttle pressure of 950 psig and a reactor pressure of ~1005 psig.

14. At 400 psig, the SJAEs, preheaters and gland seal steam can be switched from auxiliary steam to reactor steam. Place a RFP in operation.

15. At 920 psig, the EHC system will start to open BPVs.

16. The reactor mode switch can be transferred to "RUN" after ensuring that the following
    a. ARPMs are reading > 5% and < 12%.
    b. MSIVs are open
    c. Condenser vacuum > 23" Hg.
    d. Reactor pressure >850psig and low reactor pressure alarms are clear.

17. Transfer the recorder switches to the APRM and withdraw the IRM detectors.

18. Continue to pull control rods until $1^{1}/_{2}$ BPV's are open to the condenser. Discontinue rejecting water from the cleanup system when the steaming rate exceeds CRD Hydraulic System makeup. Place the STARTUP LEVEL CONTROLLER in AUTO. Roll the main turbine. Synchronize the generator to the grid and apply initialload.

19. Withdraw control rods and increase power to ~20%. Place the second condensate pump, condensate booster pump, and additional condensate demineralizer units in service as power increases.

20. At 40% power place the second RFP in service.

21. Continue rod withdrawals in combination with flow changes as recommended by the nuclear engineer until the desired power level is reached.

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Chapter 2.0

Class Exercises

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Prior to the discussion of transient analysis it is essential to review some of the control systems covered in the Systems Course. The purpose of this section is cover the electro hydraulic control (EHC) system's response to various failures. Using the attached EHC system figures, discuss the plant response to each of the following events:

1. Failure of the turbine load set causing it to run back to zero (0).

2. The cooldown bypass jack signal is increased to 3%.

3. Failure of the in service pressure regulator to maximum signal out.

4. Failure of the in service pressure regulator to minimum signal out.

The discussion of the plant events, listed above, should include the transient and steady state conditions.

The initial plant conditions are indicated below:

Reactor Power	100%
Total Core Flow	100%
Reactor Pressure	1005 psig
Turbine Inlet Pressure	950 psig
Turbine Load Selector	100%
Turbine Speed Set	Synchronous Speed Selected
Pressure Set	920 psig
Max. Combined Flow set	105%
Load Limit Set	100%
Bypass Capacity	25%

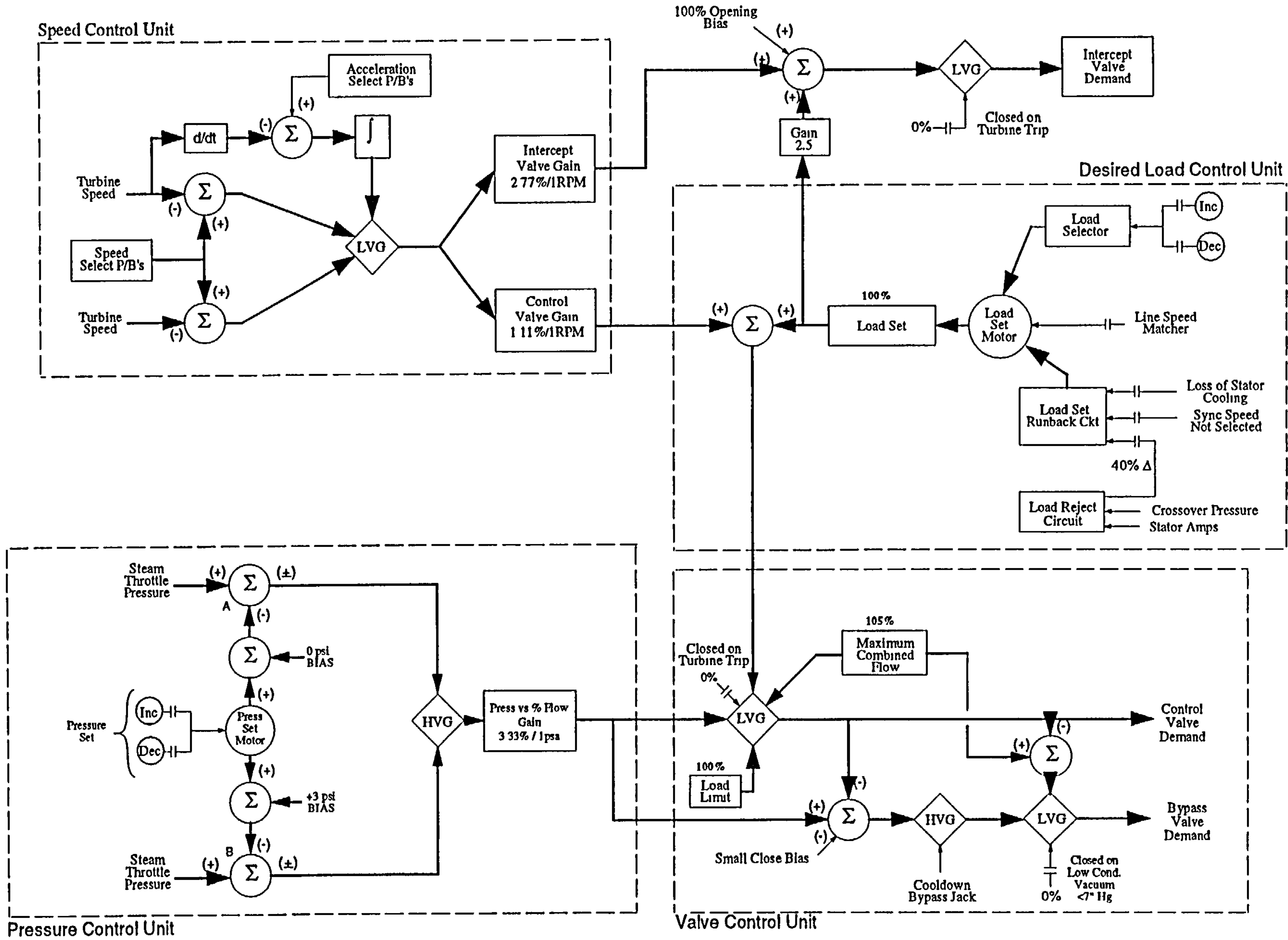

Figure 2.1-1 Electro Hydraulic Control System Logic

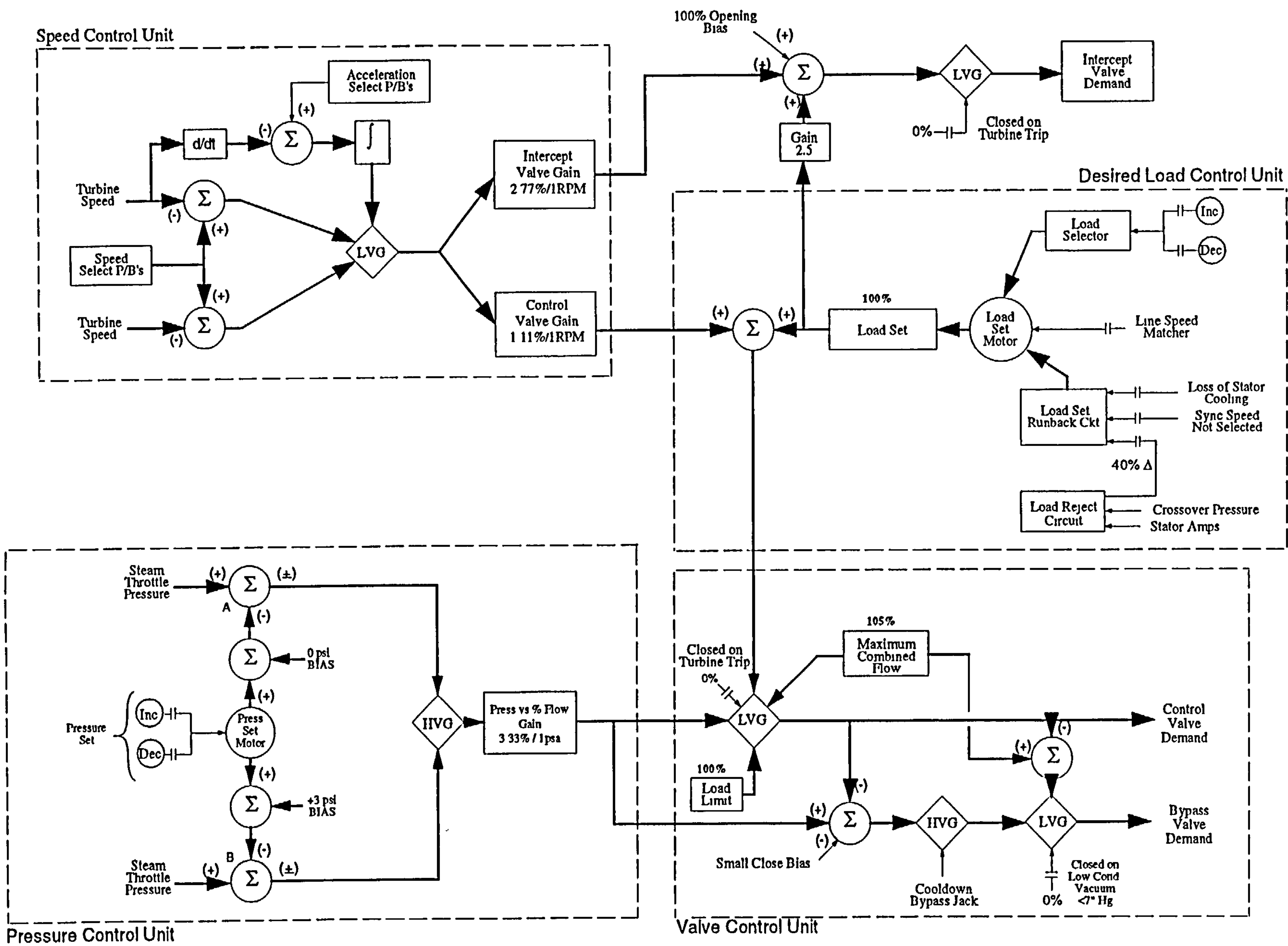

Figure 2.1-2 Electro Hydraulic Control System Logic

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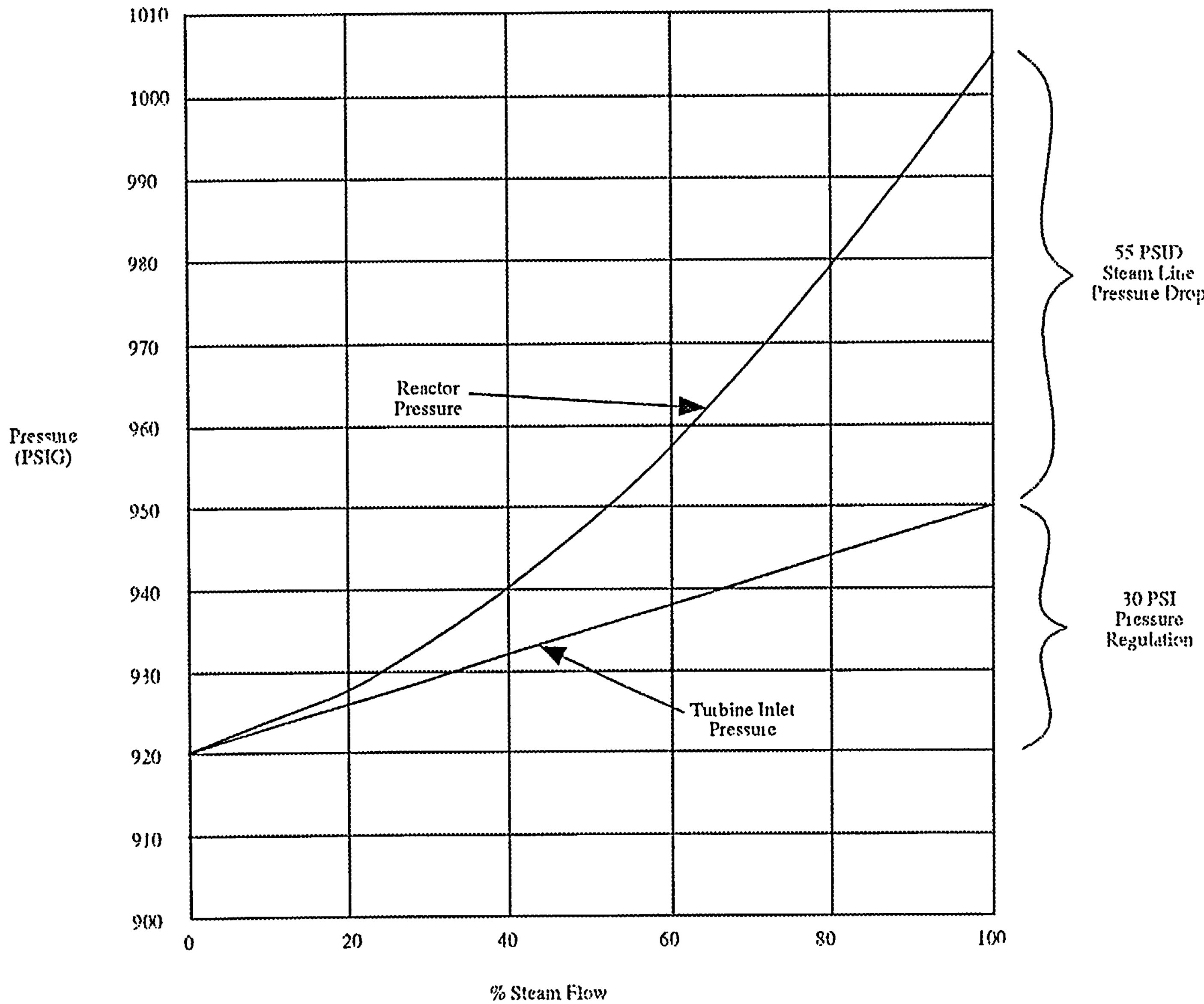

Figure 2.1-3 Pressure Control Spectrum

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2.2 CORE HEAT BALANCE

Learning Objectives

1. List three purposes of a core heat balance.

2. List the three methods that can be used to obtain core thermal power.

3. List the parameters used in a heat balance calculation and indicate the most critical parameter.

2.2.1 Introduction

The thermal power of the reactor core is determined by a heat balance on the nuclear boiler using operating data. Under steady state conditions, the nuclear boiler heat output is obtained as the difference between the total heat removed from the boiler system minus the total heat added in the flow streams returning to the boiler.

A core heat balance in the power range, greater than or equal to 10% power, is made to ensure that the core is operated at all times within licensed thermal limitations and/or fuel warranty requirements. The results of heat balance calculations also provide input to additional core calculations (i.e., CPR & APLHGR).

2.2.2 Methods of Calculation

Four methods of calculating the energy output of the core by heat balance are used:

- Short Form Method - used when a fast estimate is needed and a high degree of accuracy is not essential.

- Long Form Method - considers all heat losses and additions.

- Process Computer - Normal calculational method.

- Off-line Computer

Either the manual long form method or the off-line computer method is required when the process computer is unavailable. This instruction covers the manual method long form and is addressed in NRC "Inspection and Enforcement Manual" chapter (IMC), 61706B.

The core thermal power is obtained by writing an energy balance on a system composed of the reactor vessel, recirculation loop piping, and cleanup demineralizer piping. Flows entering the system are the reactor feedwater flow and the control rod drive system flow. The only flow assumed to be leaving the system is the primary steam flow. Non-flow power losses are the radioactive power loss and the net power transferred across the boundary of the cleanup demineralizer loop.

Figure 2.2-1 is a schematic diagram of the energy inputs and outputs to be evaluated. Mathematically, the heat balance equation is derived as follows:

The heat outputs from the system include:

Main Steam = $m_{MS} \times h_{MS}$ (equation A)

Cleanup System = $m_{CU} \times (h_{in} - h_{out})$ (equation B)

Where: $m_{CU} = m_{CU(A)} + m_{CU(B)}$

Fixed Losses = Q_{FL} (equation C)

The heat inputs to the system include:

Feedwater = $m_{FW} \times h_{FW}$ (equation D)

CRD Hydraulic = $m_{RD} \times h_{RD}$ (equation E)

Recirculation Pumps = Q_P (equation F)

Core Power = Q_C (equation G)

Since the measurement of main steam flow is normally much less accurate than the measurement of feedwater flow, and since this is a closed system, let:

$$m_{MS} = m_{FW} + m_{RD} \quad \text{(equation H)}$$

Substituting Equation H into Equation A:

$$\text{Main Steam} = h_{MS} \times (m_{FW} + m_{RD}) \quad \text{(equation I)}$$

The total heat outputs are therefore:

$$\text{Outputs} = K[h_{MS}(m_{FW} + m_{RD}) + m_{CU}(h_{in} - h_{out})] + Q_{FL} \quad \text{(equation J)}$$

The total heat inputs are therefore:

$$\text{Heat Inputs} = K[(m_{FW} \times h_{FW}) + (m_{RD} \times h_{RD})] + Q_P + Q_C \quad \text{(equation K)}$$

Since the heat inputs must equal the heat outputs, equation J is set to equation K:

$$K[(m_{FW} \times h_{FW}) + (m_{RD} \times h_{RD})] + Q_P + Q_C = K[h_{MS}(m_{FW} + m_{RD}) + m_{CU}(h_{in} - h_{out})] + Q_{FL} \quad \text{(equation L)}$$

Solving Equation L for Core Power:

$$Q_C = K[\,h_{MS}(m_{FW} + m_{RD}) + m_{CU}(h_{in} - h_{out}) - m_{FW}h_{FW} - m_{RD}h_{RD}] + Q_{FL} - Q_P \quad \text{(equation M)}$$

Combining all terms and rearranging yields the equation representing total Core Thermal Power:

$$Q = K[\,m_{FW}(h_{MS} - h_{FW}) + m_{RD}(h_{MS} - h_{RD}) + m_{CU}(h_{in} - h_{out})] + Q_{FL} - Q_P \quad \text{(equation N)}$$

Where:

Q_c = Core thermal power (MWt)

K = 2.93 x 10-7 MWt-hr/BTU

m_{FW} = Feedwater Flow (lbs/hr)

m_{RD} = Control rod drive flow (lbs/hr)

m_{CU} = Clean-up System flow (lbs/hr)

h_{MS} = Enthalpy of main steam (BTUlb)

h_{FW} = Enthalpy of feedwater (BTU/lb)

h_{RD} = Enthalpy of control rod drive flow (BTU/lb)

h_{in} = Enthalpy of inlet flow to cleanup system (BTU/lb)

h_{out} = Enthalpy of return flow from cleanup system (BTU/lb)

Q_{FL} = Fixed Losses (MW) = 0.6 MW

Q_P = Recirculation pump work (7.6 MW)

For the case in which an estimate of this value is desired rapidly, the curves of Figure 2.2-2 may be used. These curves are based upon a simplification of equation N of the form:

$$Q_c = K\,[m_{FW}(h_{MS} - h_{FW})] + \text{Constant} \quad \text{(equation 0)}$$

The above constant is composed of all the small heat input and output terms that complete the thermal energy balance. It is defined as:

$$\text{Constant} = K\,[\,m_{RD}(h_{MS} - h_{RD}) + m_{CU}(h_{in} - h_{out}) + Q_{FL} - Q_P \quad \text{(equation P)}$$

2.2.3 Heat Balance Calculation Problem

Table 2.2-1 includes a practice problem for performing a core heat balance. Using the values on form TI 1.1 of the table and the attached steam tables, calculate the core thermal power.

2.2.3.1 Assumptions

Core thermal power is equal to or greater than 329 MWt (10% power)

Reactor Water Cleanup system flow is directed back to the reactor.

Exponents - powers of 10 are compensated for in the formula derivations or are specifically indicated.

Assume atmospheric pressure is 15 psia.

Check results against the nomograph.

2.2.4 Licensed Power Level

The following is the text of an internal NRC letter from Mr. E. L. Jordon (Director, Office of I&E, August 22,1980) to the Branch Chiefs of Reactor Operations in each Region. The letter provides guidance to inspectors for determining licensee compliance with Licensed Power limits. This guidance is still in effect today. A copy of the letter can be found in the Document Control System:

Dating back to at least 1974, there have been many lengthy "discussions" regarding the exact meaning of "full, steady-state licensed power level" (and similarly worded power limits). We do not believe the real safety benefits that might be derived from an NRC-wide agreement would be worth the further expenditure of manpower in meetings, etc. that would be required to achieve a consensus.

We do realize that some common uniform basis for enforcing maximum licensed power is needed by I&E inspectors. Therefore, until and unless an NRC-wide position is put forward and agreed upon (and as stated, I&E does not propose to initiate proceedings to that end), I&E will use the following guidance:

The average power level over any eight hour shift should not exceed the "full steady-state licensed power level" (and similarly worded terms). The exact eight hour periods defined as "shifts" are up to the plant, but should not be varied from day to day (the easiest definition is a normal shift manned by a particular "crew"). It is permissible to briefly exceed the "full, steady-state licensed power level" by as much as 2% for periods as long as 15 minutes. In no case should 102% power be exceeded, buy lesser power "excursions" for longer periods should be allowed, with the above as guidance (i.e., 1% excess for 30 minutes, 1/2% for one hour, etc., should be allowed). There are no limits on the number of times these "excursions" may occur, or the time interval that must separate such "excursions", except note that the above requirement regarding the eight hour average power will prevent abuse of this allowance. The above is considered to be within the licensing basis and, therefore, acceptable to us, and it is also fair to the utilities and their ratepayers.

2.2.5 100% Power

Core thermal power for nuclear power plants is controlled on the basis of a licensed thermal power rating. Nuclear instruments and plant calorimetrics are used to monitor reactor power. The accuracy of the calorimetric power determination (heat balance)is sensitive to several measurements, but is most affected by feedwater flow measurement accuracy. Thus, an accurate determination of core thermal power hinges on the accurate knowledge of feedwater flow.

Two non-conservative errors in feedwater flow measurement led to power in excess of the licensed thermal power limit at FitzPatrick. The feedwater flow transmitters were replaced on October 3, 1988, but were not calibrated properly. The calibration was completed on November 14, 1989. When more accurate transmitters were placed in service on January 29, 1990, the power level was found to exceed the licensed limit. Power was immediately reduced. Flow element vendor input errors have since been identified and corrected.

Operation in excess of the thermal power limit occurred at Oyster Creek on May 11, 1990 and again on August 1, 1990. The first event occurred because of a miscalculation in the plant heat balance equation. The second event, August 1, 1990, was a result of feedwater flow calibration calculation which was approximately 2% in the nonconservative direction.

Operation in excess of the thermal power limit occurred at Cooper Nuclear Station from 1980 to April 1994, at those times when the reactor was operated at full power. The actual reactor power was approximately 2400 MWt while the calculated power level was 2381 MWt. This was attributed to the licensee not compensating for an error in the calibration of the pressure transmitters used for feedwater flowrate determination.

The common link in all of these cases is that there was no indication of a problem until an independent means of measurement or calculation was employed. The existing feedwater flow measurement instrumentation, for most BWR plants, consists of a differential pressure transmitter providing an output proportional to the differential pressure across the flow nozzle. Resistance thermometers (or thermocouples) measure the feedwater temperature. Typically, these outputs are supplied to the plant computer where the density and enthalpy are calculated with the aid of synthesized ASME steam tables. Thermal power is then calculated by the plant computer.

Operation experiences in the United States, Japan, and Germany has shown that venturi flow measurement accuracy is susceptible to degradation. The principle source of degradation is fouling with corrosion deposits, which adhere preferentially to the nozzle throats of the venturi tubes. The corrosion deposit fouling causes an increase in the differential pressure measured for a given volumetric flow and results in erroneously high feedwater flow readings. When the overestimates of feedwater flow are used to calibrate the nuclear instruments, these calibrations result in operating with the actual core thermal power below the intended level. Various studies have shown that fouling recurs during each operating cycle and can contribute up to 2 to 3 percent reduction in thermal power, $$$$.

In the August 26, 1999 issue of Nucleonics Week an article stated "GE PROPOSES BWR UPRATES OF 1% BASED ON GENERIC APPROACH". The article stated that in mid August General Electric (GE) submitted a proposal to the NRC that would allow BWR owners to proceed with 1 % uprates by reducing conservatism in calculating reactor power.

GE wants to take advantage of the awaited NRC approval of a similar generic uprate for PWRs based on uncertainty reductions stemming from use of a new feedwater measurement technology.

The NRC approved an exemption to allow Texas Utilities to reduce the error assumption calculated into its heat balance from 2% to 1% at its two Comanche Peak PWRs, and the utility followed with a request for a power uprate.

The Caldon Leading Edge Flow Meter (LEFM) is currently the only such instrument approved by the NRC but ABB Combustion Engineering may soon introduce the Crossflow, its own feedwater flow measuring device and is closely following GE's generic proposal.

On May 3, 2000, the NRC approved a rule change amending 10CFR50 Appendix K to permit power increases based on improvements in accuracy of the instrumentation used to measure thermal power. These power increases, referred to as "Appendix K Uprates"' are relatively small increases on the 1% to 1.7% range, depending on the demonstrated instrument accuracy.

It is anticipated that licensees will make use of the new measurement instruments such as the LEFM mass flow and temperature measurements by directly substituting the new information in the plant computer. The plant computer would then calculate enthalpy and thermal power as it does now. In order to maintain control of thermal power at 100 percent power, a real-time display of thermal power, as calculated using the new technology, will be available in the main control room for the reactor operator's use. The operators would then use the new display to maintain reactor power at or below the licensed thermal power limit. A validity indication will also be present to alert the operators of the condition of the new instruments.

Described below are three ultrasonic technologies used in the measurement of volumetric flow in a pipe:

- Chordal Transit Time system (LEFM) consisting of arrays of ultrasonic transducers housed in fixtures in a pipe so as to form parallel, precisely defined acoustic paths. The times of flight of pulses of ultrasonic energy traveling along these paths are measured to determine the volumetric flow and the velocity of sound of the flowing fluid. A numerical integration method is used to determine the volumetric flow rate directly from the meter's four path velocities without the need for a pipe area measurement.
- Externally Mounted Transit Time systems consisting of ultrasonic transducers mounted on the exterior of the pipe so as to form one or more diagonal and diametral acoustic paths. The times of flight of pulses traveling between pairs of transducers are measured to determine the axial fluid velocity projected onto the acoustic path (In some designs, the fluid sound velocity is also measured.). With knowledge of the shape of the axial velocity profile, the mean fluid velocity can be inferred from the axial fluid velocity measurement. The volumetric flow is then calculated as the product of the mean axial velocity and the pipe cross sectional area.
- Cross Correlation systems(Canadian General Electric) consisting of two pairs of ultrasonic transducers mounted so as to form two parallel diametral paths, perpendicular to the axis of the pipe, and separated by a known axial distance. One transducer in each path continuously transmits ultrasound to the opposite transducer on that path. The received signal for the upstream path is subjected to an adjustable time delay, then cross correlated with the downstream signal. A characteristic fluid velocity is calculated from the quotient of the distance between acoustic paths and the time delay at which maximum correlation is achieved. The mean axial velocity is inferred from this characteristic fluid velocity. The volumetric flow is then calculated as the product of the mean axial velocity and the pipe cross sectional area.

2.2.6 Summary

The thermal power of the reactor core is determined by a heat balance on the nuclear boiler using operating data. Under steady state conditions, the nuclear boiler heat output is obtained as the difference between the total heat removed from the boiler system minus the total heat added in the flow streams returning to the boiler.

A core heat balance in the power range, greater than or equal to 10% power, is made to ensure that the core is operated at all times within licensed thermal limitations and/or fuel warranty requirements. The results of heat balance calculations also provide input to additional core calculations (i.e., CPR & APLHGR).

Either the manual long form method or the off-line computer method is required when the process computer is unavailable.

Table 2.2-1 TI 1.1 Core Heat Balance

	Parameter	Panel	Instrument No.	Units	Reading
(1)	m_{FW}	9-5	FR-3-78	10^6lb/hr	13.3
(2)	m_{RD}	9-5	FI-85-11A	gpm	80
(3)	$m_{CU(A)}$	9-4	FI-69-35	gpm	135
(4)	$m_{CU(B)}$	9-4	FI-69-60	gpm	0.0
(5)	T_{FW}	9-6	TI-3-48	°F	375
(6)	$T_{CU(in)}$	9-4	TI-69-6	°F	526
(7)	$T_{CU(out)}$	9-4	TI-69-6	°F	430
(8)	T_{RD}		Spec. Meas.	°F	85
(9)	P_R	9-5	PR-3-53	psig	1010
(10)	P_{RD}	9-5	PI-85-13A	psig	1335
(11)	$Q_{Loop\ A}$	9-4	EI-96-14A	MW	3.75
(12)	$Q_{Loop\ B}$	9-4	EI-96-14B	MW	3.75

Data Taken ____________
Initials

Table 2.2-1 TI 1.1 Core Heat Balance (Continued)

	Quantity	Data Used	Value (BTU/lb)
(13)	h_{MS}	(9)	________
(14)	h_{FW}	(5) & (9)	________
(15)	h_{in}	(6) & (9)	________
(16)	h_{out}	(7) & (9)	________
(17)	h_{RD}	(8) & (9)	________

Note: Assume that atmospheric pressure equals 15 psia.

enthalpy (h): A quantity associated with a thermodynamic system expressed as the internal energy of a system plus the product of the pressure and volume of the system.

thermodynamics: The science concerned with the relations between heat and mechanical energy or work, and the conversion of one into the other.

entropy: A measure of the amount of work unavailable for work during a natural process.

Table 2.2-1 TI 1.1 Core Heat Balance (Continued)

	Quantity	Data Used	Value (MWt)
(18)	Q_{FW}	(1) x (14) x .293	______
(19)	Q_{RDin}	(2) x (17) x (1.47×10^{-4})	______
(20)	Q_p	(11) + (12)	______
(21)	Q_{Tin}	(18) + (19) + (20)	______
(22)	Q_{MS}	(1) x (13) x .293	______
(23)	Q_{RDout}	(2) x (13) x (1.47×10^{-4})	______
(24)	Q_{CU}	[(3) + (4)] x [(15) - (16)] x (1.47×10^{-4})	______
(25)	Q_{FL}	Special Measurement	0.6
(26)	Q_{Tout}	(22+23+24+25)	______
(27)	Q_C	(26) - (21)	______

Calculation Done By ______________

Properties of Superheated Steam and Compressed Water (Temperature and Pressure)

Press. psia	1000	1025	1050
Tsat	544.58	547.56	550.53
Sat Steam	1192.9	1191.95	1191.0
Sat. Water	542.55	546.35	550.15
540	536.69	536.65	536.60
530	524.12	524.09	524.05
520	511.79	511.77	511.74
510	499.69	499.68	499.66
450	430.55	430.57	430.58
440	419.45	419.47	419.49
430	408.46	408.48	408.50
420	397.55	397.58	397.60
410	386.72	386.75	386.77
400	375.96	375.99	376.02
390	365.27	365.31	365.34
380	354.65	354.69	354.72
370	344.08	344.12	344.16
360	333.57	333.61	333.65
100	70.63	70.70	70.76
90	60.69	60.70	60.83
80	50.76	50.83	50.89
70	40.82	40.89	40.96
60	30.88	30.95	31.02

Properties of saturated Steam and Water (Pressure)

Pressure psia	Temperature °F	h_f	Enthalpy, Btu/lbm h_{fg}	h_g
1050	550.53	550.1	640.9	1191.0
1040	549.36	548.6	642.8	1191.4
1030	548.18	547.1	644.7	1191.8
1020	546.99	545.6	646.6	1192.2
1010	545.79	544.1	648.5	1192.6
1000	544.48	542.6	650.4	1192.9
990	543.36	541.0	652.3	1193.3
980	542.14	539.5	654.2	1193.7
970	540.9	537.9	656.1	1194.0
960	539.65	536.3	658.0	1194.4

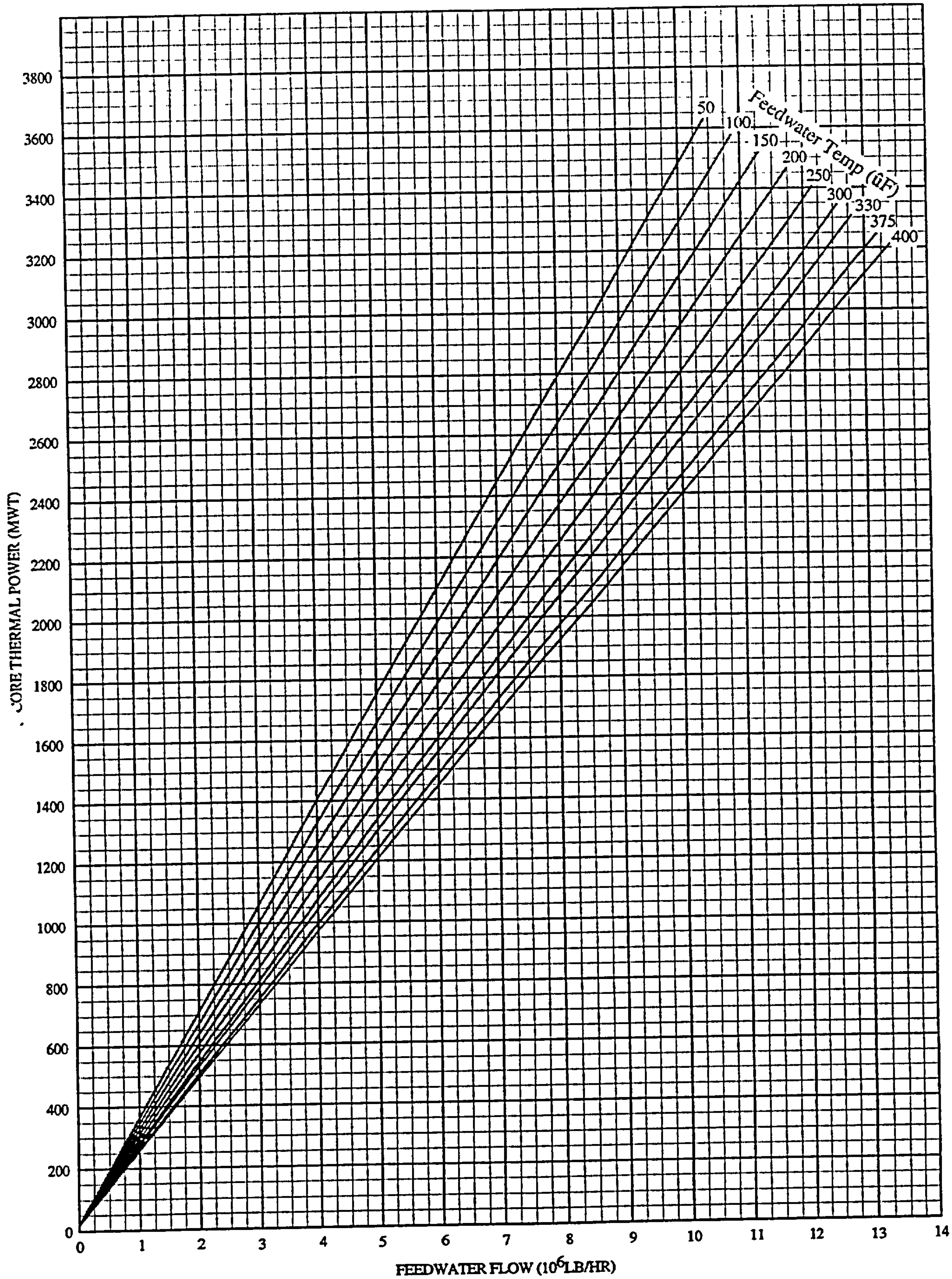

Figure 2.2-1 Simplified Short Form Core Heat Balance

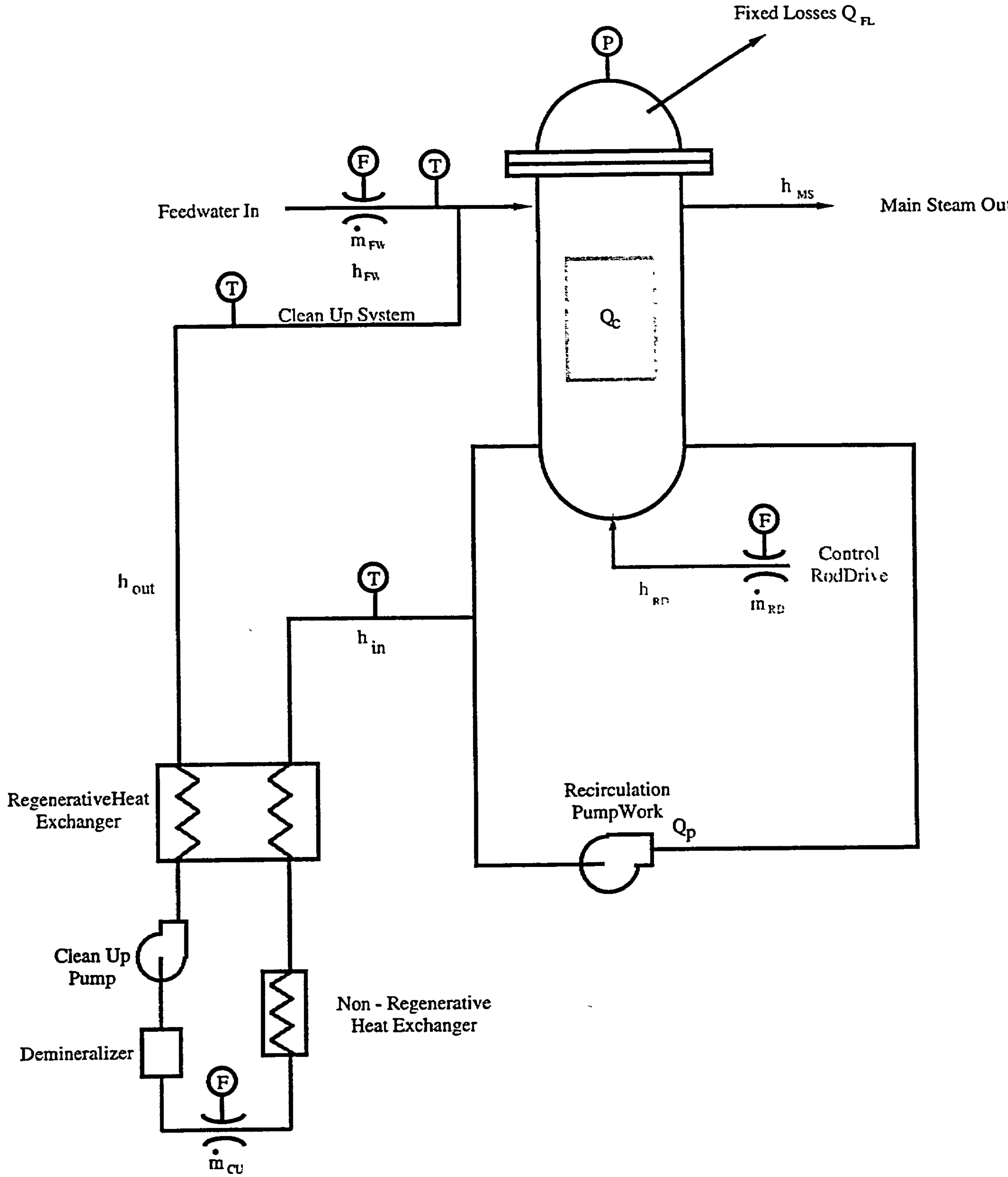

Figure 2.2-2 Simplified Core Heat Balance Diagram